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IN THE

United States Court of Appeals

FOR THE FIFTH CIRCUIT

No. 71-2761

On Petitions to Review Orders of the
Federal Power Commission

JOINT APPENDIX

(PART II)

SOUTHERN LOUISIANA AREA RATE CASE
PLACID OIL COMPANY, ET AL.,
Petitioners,

v.

FEDERAL POWER COMMISSION,
Respondent.

Prehearing Conference Exhibit No. 1

[7,832]

EXHIBIT No. 1

STAFF PROPOSED QUESTIONNAIRE

OFFSHORE SOUTHERN LOUISIANA

Docket No. AR69-1

Washington, D.C. 20426
August 14, 1969

Prehearing Conference Exhibit No. 1
[7,833]

QUESTIONNAIRE REQUESTING DATA RELATED TO ZONES 2, 3 AND 4, OFFSHORE SOUTHERN LOUISIANA

General Instructions: This questionnaire was prepared with the objective of collecting a history of data relating to operations involving Zones 2, 3 and 4, offshore Southern Louisiana. Detailed data is requested on Schedule Nos. 1, 2, 3, 4, 5 and 7 for non-associated and predominately non-associated gas operations. Schedule 4 further provides for the reporting of aggregate costs which are common to operations in addition to the non-associated and predominately non-associated gas operations. Predominately non-associated gas operations are defined as those reporting units (lease or field) for which the ratio of non-associated gas to crude oil total original proved reserves is 125 Mcf per barrel or greater. The summary data requested on Schedule A relates to all other operations in Zones 2, 3 and 4 offshore Southern Louisiana where gas or oil reserves are proven. The data requested on Schedule No. 6 pertains to all unproven properties in the subject area.

The reporting company may report the data on any level of working interest but is required to show the interest covered for each item of data where less than 100% interest is reported for each item. Other general instructions are as follows:

1. Except as noted, all data should be shown in the proper annual period for which the cost, production, operation, etc., pertained. If necessary the completion date of a project may be used in lieu of the year of the expenditure. An asterisk precedes each item for which data should be reported in the year of incurrence.

2. All gas volumes should be reported at 15.025 psia and 60°F and all liquid volumes should be reported in barrels (42 U.S. gallons) at 60°F.
3. Each deviation from the requested reporting basis should be noted on the schedule affected together with a full description of the nature of the deviation.
4. All money amounts should be reported to the nearest dollar and should be identifiable to one or more company records.
5. Significant out-of-period adjustments should be fully described by footnotes.
6. A proven reporting unit is described as having known commercial or paying quantities of oil, gas or both. Depleted, shut-in and on-stream operations should be included in this category.

[7,834]

7. In reporting well data, use the following definitions:

   (a) Oil wells are wells having the capability of producing commercial hydrocarbons existing primarily or wholly as liquids in one or more producible zones.

   (b) Gas wells are well having the capability of producing commercial hydrocarbons existing primarily or wholly in the gaseous phase in one or more producible zones. Also include wells completed or to be completed in a gas cap where gas production was or will be unaffected by oil well production from other wells.

(c) Combination wells are wells producible from two or more zones and at least one zone is producible of mainly commercial crude and at least one zone is producible of commercial non-associated gas.

(d) Dry holes are wells drilled with the intent of finding hydrocarbons or are drilled to provide service or knowledge but which have no commercial quantities of hydrocarbons. Wells in the process of being drilled and incomplete on December 31, 1968, where drilling had not yet resulted in a commercially producible zone, should be included in this category but noted to indicate this situation.

(e) Developmental wells or developmental dry holes are drilled for the purpose of developing reserves reasonably established by previous drilling.

(f) Exploratory wells or exploratory dry holes are drilled without reasonably established knowledge of underlying reserves.

(g) Footage should reflect the greatest depth penetrated measured down a wellbore.

Specific Schedule Instructions

Schedule No. 1, Sheets 1 and 2: Expenditures, Cost and Supplementary Data Attributable to Individual Proven Reporting Units—

Working interest in the unit (sheet 1, lines 4 and 5) should reflect the most current distribution of interest in the operation.

In general most of the expenditures reported on this schedule do not require allocation to the reporting unit by the reporting company.

Prehearing Conference Exhibit No. 1

[7,835]

Initial and subsequent leasehold expenditures (sheet 1, lines 6 and 7) should include bonuses, rentals, fees, etc. which are associated with the acquisition of mineral rights from the federal government. Royalties based on Production or Revenue should be excluded. If the lease or unit or portion thereof was acquired from a party other than the government, report the details of the purchase by footnote.

A proven reporting unit should be classified as developed (sheet 1, line 8) if drilling has been completed pursuant to current company planning.

The future development of partially developed properties (sheet 1, lines 9-12) should reflect company plans for each well now expected to be drilled.

The expenditures to be shown on sheet 1, lines 13-15 are generally related to methods of operation whereby company owned permanent structures are installed for drilling and the installation remains for production purposes. In reference to well drilling from these structures, identify those wells which are bottomed in an adjacent unit.

Producing property operating expense (lines 16-20) should be reported for 1968. Identify any amounts allocated to leases or units and explain the method and nature of the expense with footnotes. The following should be excluded: (1) Costs and expenses applicable to exploration and development activities as reported in Schedule Nos. 4 and 6; (2) Costs and expenses applicable to onshore operations serving offshore leases; (3) Depletion, depreciation and amortization expense; (4) Costs and expenses applicable to royalties and net profit interests; (5) Production taxes.

Prehearing Conference Exhibit No. 1

The individual well data (sheet 2) for all drilling prior to December 31, 1968, should be reported in conformity with the well definitions shown in the general instructions. Do not include expenditures repotred on sheet 1 at line 13 or Schedule No. 4.

Production equipment expenditures (sheet 2, lines 15-16) relate to offshore based equipment serving the lease or unit. Expenditures related to offshore based production equipment serving more than one lease or unit may be allocated to individual leases or units. Identify any amounts so allocated to leases or units and explain the method and nature of the expenditure with footnotes. Onshore production equipment serving offshore units should be reported on Schedule No. 4.

Schedule No. 2: Disposition of Gas and Related Liquid Production Traced to Each Lease or Unit Shown on Schedule No. 1. (6/6 Production)

Produced gas volumes (lines 1 and 4) should reflect total production which is saved, sold or put to useful purposes, but should exclude on-lease gas lift gas and flared and vented gas. Gas which is flared or vented should be included under "Disposition of Produced Gas" at lines 7 and 8. Volumes reported to the Louisiana Department of Conservation will suffice

[7,836]

for reporting flared and vented gas. Produced gas volumes (lines 1 and 4) should include the volume of liquids and liquid vapors separated (condensate) or extracted (LPG, natural gasoline, etc.) from the gas with onshore facilities or extraction plants.

Crude production (line 5) should represent volumes after normal separation (assumes onshore operation) of gas and BS&W at the lease level.

Offshore separated condensate (line 2) should not include volumes separated and then recombined or remixed with the gas for transportation purposes. Onshore separated condensate (line 3) should reflect total volumes and is not intended to coincide with the leases' share of condensate revenue at line 27.

Under the category "Gas Delivered Onshore" at lines 13 and 18, the term shrinkage should encompass the total loss and consumption of gas due to the extraction and/or separation of liquids.

The term "Intermediate" at line 20 applies to transporters who have no ownership interest in the gas as produced and do not obtain title to the gas. These companies charge the producers or purchasers for the transportation service involved.

The "Revenue From Liquids" (lines 24-27) should include the unit or lease owners' share of liquid revenue which is recorded in lease accounts, including the property units share of revenue from liquids separated and/or extracted onshore.

Schedule No. 3: Supplementary Gas Sales and Operating Data Traced to Each Lease or Unit Shown on Schedule No. 1.

The information reported on this schedule should reflect the most current data applicable to the lease or unit.

Prehearing Conference Exhibit No. 1

Schedule No. 4: Expenditures and Supplementary Data Related to Operations and Equipment Serving More Than One Lease or Unit.

In general the expenditures reported on this schedule cover aggregates larger than those reported on Schedule Nos. 1 and 6. They may (a) relate to aggregated non-associated and predominately non-associated gas operations or (b) may be common to both oil and gas reservoir operations. Certain allocated amounts are requested and in all of these instances an explanation of the allocation is required by footnote. Expenditures for contracted services should be included wherever applicable.

[7,837]

Equipment expenditures (line 1) relate to company-owned equipment which generally assists the contract drilling operation. The total number of wells served (line 2) should be reasonably estimated over the useful life of the equipment.

Onshore production equipment or facilities data (lines 5-8) should pertain to those types which would normally be located on a lease or within a field if the operation were onshore. Gas processing plant data should be excluded.

Other onshore equipment, etc., data (lines 9-11) would include those types which the company utilizes generally for more than one function, e.g., exploration, drilling and production.

Geological and Geophysical data (lines 12 and 13) should include company-owned equipment and facilities used solely for these types of surveys as well as the cost of contracted surveys. The general area surveyed should

include Block Nos. and area locations and should be shown under the related expenditure in the proper time period.

Other E&D expenditures (lines 14 and 15) should exclude bottom hole and well contributions as well as other expenditures reported in other sections of the questionnaire.

Schedule No. 5: Supplementary Data Related to Certain Investment and Expenses.

The production investment reported on this schedule should reflect year-end net working interest amounts as carried on the financial accounting records of the reporting company. Where intangible development costs are not capitalized and subsequently amortized for producing properties on company records, a restatement should be made on a capitalized basis and amortization computed by generally accepted procedures, such as the unit of production method.

The OCS No.(s) and percent of working interest should be reported for each producing property unit, or for each non-producing property unit carried in the company's non-producing acreage accounts. When prior years data are requested for properties transferred from non-producing acreage accounts to company producing leasehold accounts, the accounting method for restatement, if any, of investment which had been previously amortized should be described.

The leasehold investment and depletion expense should generally reflect costs relative to the purchase of the mineral rights (bids, fees, etc.) and other applicable early outlays such as surveying and assigned geological and geophysical costs which had been capitalized. The in-

tangible development costs and the related amortization expense pertain primarily to the successful unsalvable well drilling costs with other associated intangible items, whereas the investment in lease and well equipment and the depreciation expense relate to tangible production equipment.

[7,838]

Schedule No. 6: Data Related to Unproven Leases.

Report all data related to unproven leases for 1968 and prior years.

Data relative to lease acquisitions, as reported in columns (d) through (h), sheet 1, should be footnoted to indicate those properties acquired from other operators through any form of inter-company transaction. The footnote should state the party from whom the property was purchased and the type of transaction. The absence of a note will thus indicate those properties acquired from the United States Government.

If a respondent reports an interest in addition to his own show on column (n), shet 1, the identification of those joint lease owners and their respective percentage interest of total working interest. This information need be provided only for properties currently being held by the reporting company and does not apply to acreage reported as sold or released.

The total expenditures requested in column (g), sheet 2, should reflect drilling and abandonment costs only and should exclude those related expenditures requested on Schedule No. 4.

[7,838]

Prehearing Conference Exhibit No. 1

Schedule No. 7: Data Related to Gas-Well Gas Reserves to be Reported for Each Separate Reservoir Underlying a Property Unit.

These data (lines 1-8) should reflect the initial gas reserve determination and every redetermination of gas reserves for each reporting unit and reservoir containing non-associated gas. Dry gas excludes the vapor volume of liquids which have been or will be separated and/or extracted. Liquid to gas ratios (lines 9 and 10) should reflect actual or expected ratios relative to each reservoir estimated over the life of the project being reported.

It is requested that the gas reserves reported be defined to describe the company policy of determining reserves, *e.g.*, (1) drilled proven reserves are reserves which are determined for a limited drainage area related to existing wells; (2) drilled proven and undrilled proven reserves are reported as reserves which are determined for the full extent of the reservoir underlying the property unit without reference to the development stage or well drainage. A description of company policy should be stated on the bottom of Schedule 7.

Additional Information Requested

Map of Operations: Each reporting company should submit a map or sectional maps for the South Louisiana Offshore Area identified by Areas, Block Nos. and Zones, showing the position of company-owned properties and operations. Detailed information, clearly coded in the map legend, should encompass the following:

Prehearing Conference Exhibit No. 1

[7,839]

(1) Type of wells drilled

a. Gass Wells—No. of gas reservoirs.

b. Oil Wells—No. of oil reservoirs.

c. Combination or multiple completions—No. of gas reservoirs—No. of oil reservoirs.

d. For the above wells specify the shut-in or cased off producible zones.

e. Dry Holes.

f. Service Wells or Other (Specify).

(2) Outline general extent of each reservoir noting the type of reserves *e.g.* non-associated gas or crude oil.

(3) Outline all known salt domes existing under proven properties in the Offshore Area.

Annual Report: Each reporting company should submit its most current annual financial report.

Prehearing Conference Exhibit No. 1

[7,840]

Prehearing Conference Exhibit No. 1

[7,841]

Prehearing Conference Exhibit No. 1

[7,842]

Schedule No. 2

Disposition of Gas and Related Liquid
Production Summary by Each Lease or Unit Area on Schedule No. 1
(Report Year Ended December)

16 e

Schedule No. 3

Supplementary Gas Sales and Operating
Data Traced to Each Lease or Unit Shown
on Schedule No. 1

Lease or Unit Operator _____ OCS Nos. _____

Certificate Docket and FPC Gas Rate Schedules Covering Gas Sales From This Property Unit

	Certificate Docket Nos.	FPC GRS Designation and No.	Contract Date	Gross Sales 1968	Purchaser
1)					
2)					
3)					

Payment to Pipelines By Producers For Transporting - Offshore to Onshore - Volumes Other Than Sales Gas

4) Amount _____ Explain the Basis of Payment - - - - - -

5) Distance To Pay Point _____ Miles

Direct Industrial Sales (i.e., Sales for Which Rate Schedules Are Not Reported Above). List Data for Each Sale.

6) Contract Date _____, Price _____ ¢/Mcf,
1968 Volume _____, Transporter's Name _____,
Purchaser _____

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[7,843]

Prehearing Conference Exhibit No. 1

[7,843]

Prehearing Conference Exhibit No. 1

[7,844]

Operating Company _____

Description of Data to be Reported

		1st Question	1st Question
	Company Employees Serving Contract Drilling		
	Total Expenditures		
	Estimated Total No. of Wells Served		
	Base Year Employees Serving Both Off-Shore and On-Shore? Yes ___ No ___ Lines 1, ___ Amount 2 ___ Lines 3, ___ Amount 4 ___		
	Charges to Lessee or Wells $/; Lease No. ___ Amount 6 ___ Lines 7, ___ Amount 8 ___		
	South Louisiana Onshore Based Production Equipment or Facilities Serving Offshore Oil Production Including Gas Wells Served From Base Areas 1, 2 and 3 ___ $/		
	Oil Wells Served: ___ Gas Wells Served: ___ $/		
	Estimated Base Operating Expense, Including Labor, Supervision, Maintenance, Materials, Supplies, Utilities, Transportation, Rentals, Etc. Which Were Served Offshore Operations in Areas 1, 2, and 3 ___ $/		
	Total 1968 Operating Expense, Including 1968: Yes ___ No ___ Line 9 ___		
	Other South Louisiana Onshore Based Equipment, Facilities, Buildings, Vessels, Boats, Etc. Which Were Served Offshore Operations in Areas 1, 2, and 3, Not Included Above)		
	Total Expenditures Including Operating Expense		
	Company Allocated Amount to Areas 1, 2 and 3 $/		
	Total 1968 Operating Expense Including 1968: Yes ___ No ___ Line 9 ___		
	General Information		
	Estimated Total Expenditures		
	General Area Surveyed for 1968 Expenditures		
	Other 1968 Expenditures Not Included Above and Excluding Those Amounts Related to Dry Hole Drilling, Lease Acquisition and Detailed Covered on Schedules 2 and 4		
	Total Expenditures		
	Company Allocated Amount to Areas 1, 2 and 3 $/		

$/ Explain method and nature of expenditure.
Give your 1968 status only.
* Report by separate sheet.

Prehearing Conference Exhibit No. 1

[7,845]

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Prehearing Conference Exhibit No. 1

[7,846]

Schedule No. 6
Sheet 1 of 2 Sheets

Data Related to Unproved Leases to be Admitted
by Individual Bars

Reporting Company _____

Lease Identification			Lease Acquisition					Acreage Data				Other Lease Owners, Etate & Interest, for Each Owner
			Expenditures - $					Total Acquisition		Acreage Assigned to Oil Components		
Lease No. (a)	Area Location (b)	Block No.(s) (c)	Date Acquired (d)	No. of Acres (e)	Rental and Others (f)	Total (g)	Date (h)	Acreage (Producing Leases) (i)	Net Acres (j)	Net Acres (k)		(l)

Prehearing Conference Exhibit No. 1

[7,847]

Schedule No. 6
Sheet 2 of 2

Data Related to Unproven Leases to be Submitted
by Individual Years

Reporting Company _____

Lease and Well Identification				Individual Dry Hole Data (Where Applicable)			
OCS No. (a)	Area Location (b)	Block No. (c)	Well No. (d)	Exploratory (E) or Developmental (D) (e)	Total Footage (f)	Total Expenditure (g)

[7,848]

Prehearing Conference Exhibit No. 1

[7,848]

Schedule No. 7

Data Related to Gas Well Gas Reserves
To Be Reported For Each Separate Reservoir Underlying
a Lease or Unit

Lease OCS No.(s) _____ Area Location _____ Lease or Unit Operator _____
Block No.(s) _____ No. of Acres _____
Block Sub-Division _____ Depth to Reservoir Bottom _____

Recoverable Gas Well Gas Reserve Data (Dry Basis)

Initial Determination of Original Recoverable

1) Reserves Date _____ Volume Mcf _____

Subsequent Determinations of Total Original Recoverable Reserves (do not exclude production) due to drilling and/or Revised Data (Chronological Order)

2) Date _____ Volume Mcf _____
3) Date _____ Volume Mcf _____
4) Date _____ Volume Mcf _____
5) Date _____ Volume Mcf _____
6) Date _____ Volume Mcf _____
7) Date _____ Volume Mcf _____
8) Date 12-31-68 Volume Mcf _____

Average Liquid to Gas Ratio of Gas Well Gas Reserves

9) Condensate to Gas Well Gas Ratio Bbls./MMcf _____.
10) GPM (Gallons of Commercially Extractable Liquids per Mcf) of the gas after the Separation of Condensate _____.
11) No. of Current Producible Gas Wells Completed in this Reservoir _____.

22 e

Schedule A

Annual Data to be Reported in Composite for Zones 2, 3 and 4 Combined
Excluding Non-Associated and Predominately Non-Associated-Type Operations
Years 1959-1968

	1968	1967	1966	1965	1964	1963	1962	1961	1960	1959
A) Lease Acquisition										
1) Bonus, Fee, etc.	$									
2) Rentals & Other	$									
B) Well Drilling										
1) Gas Wells										
a) Expenditure	$									
b) Footage										
2) Oil Wells										
a) Expenditure	$									
b) Footage										
3) Comb. Wells										
a) Expenditure	$									
b) Footage										
4) Dry Holes 1/										
a) Expenditure	$									
b) Footage										
C) Liquid Revenue										
1) Crude	$									
2) Condensate	$									

NOTE: Use Instructions in Staff's Draft Questionnaire for Reporting these Data.

1/ For Proven Acreage Only Relative to the Operations Above.

23 e

[7,849]

Prehearing Conference Exhibit No. 1

[7,849]

Prehearing Conference Exhibit No. 3

[7,856]

AR69-1 PREHEARING CONFERENCE
EXHIBIT NO. 3

STAFF PROPOSED QUESTIONNAIRE
OFFSHORE SOUTHERN LOUISIANA

Docket No. AR69-1

PART 2

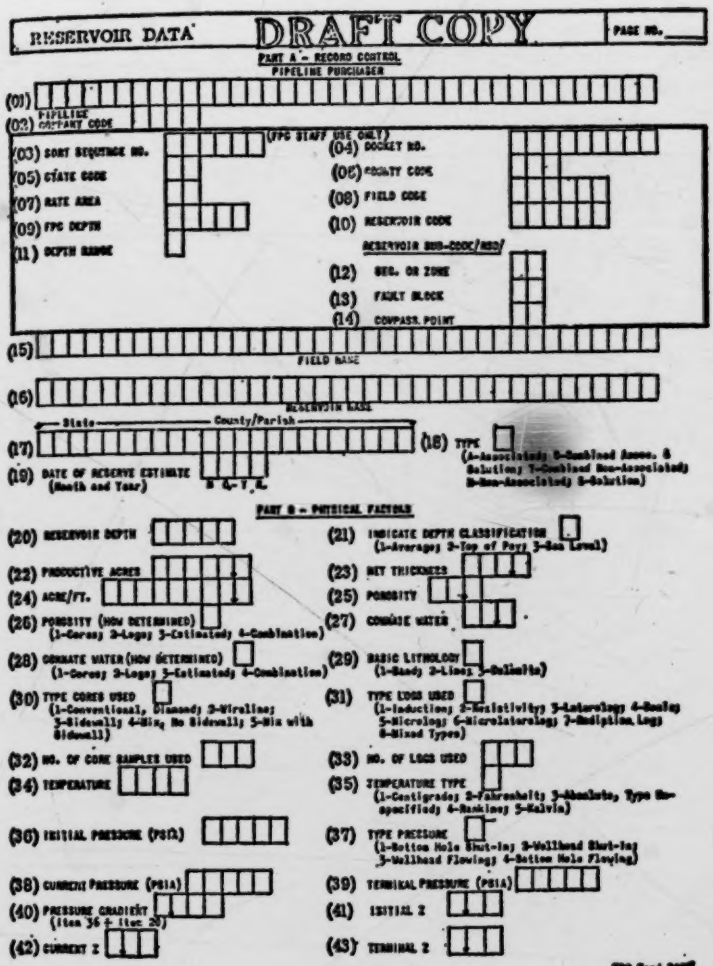
GAS RESERVES DATA

Contents

Form 1057	—	Reservoir Data	
Form 1057	—	General Instructions	p. 1
	—	Instruction, Clarification, or Description	p. 4
Appendix A	—		p. 17

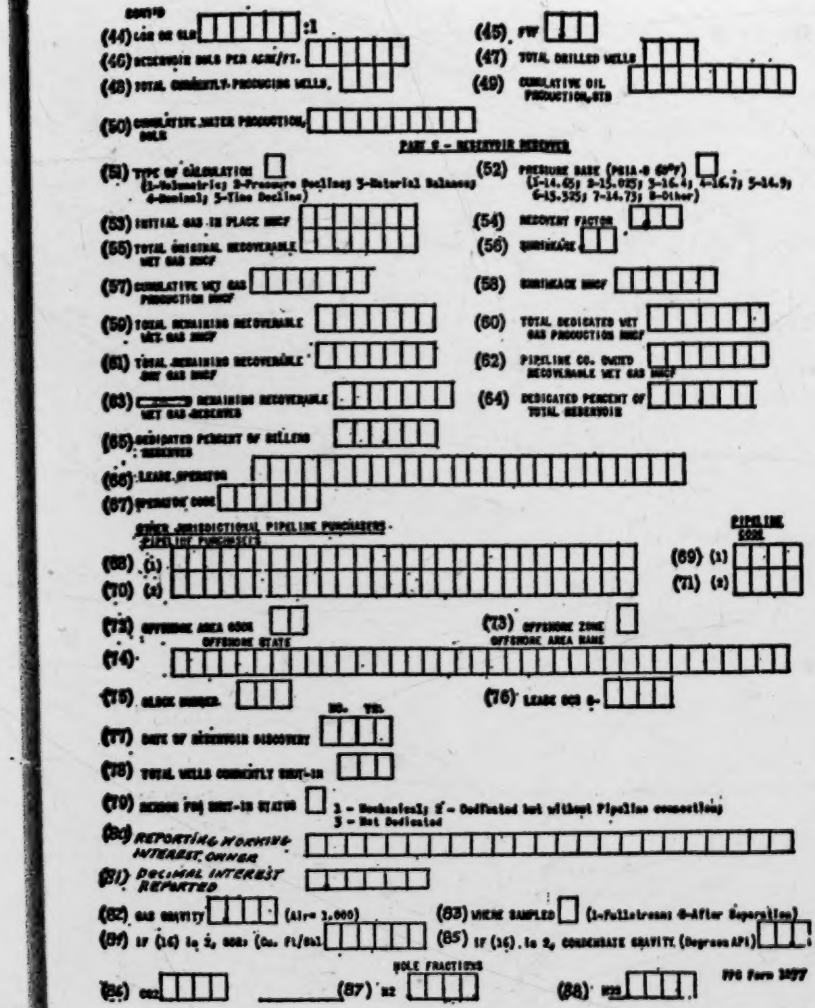
Prehearing Conference Exhibit No. 3

[7,857]



Prehearing Conference Exhibit No. 3

[7,858]



Prehearing Conference Exhibit No. 3

[7,859]

Part 2

GAS RESERVES DATA

FPC FORM 1057

GENERAL INSTRUCTIONS

1. For the purpose of this Offshore Southern Louisiana Gas Reserve Survey, the information for *each separate reservoir in each field is to be reported on an individual lease basis.* ITEM (76) of the form is the identifying Federal Offshore Lease Number for which the reserves are being reported. In the event that the reservoir underlies more than one lease, a separate Form 1057 should be completed for each lease reporting only the reserves in the reservoir underlying that specific lease. In most cases the average physical factors, other than the productive area, net thickness and acre feet, will remain the same.

2. The cut-off date for the survey will be December 31, 1968. A reserve determination for each reservoir should be as of that date and should be derived from all information that was reasonably obtainable through that date

3. To avoid duplication, only one producer, usually the lease operator, should be reporting the reserves underlying the lease. The reserves reported should be the total reserves credited to all of the working interest and royalty interest. However, when such reporting is considered to be impractical, each working interest owner under the lease may report his reserves separately. When reporting in this manner,

the reserves reported should be the working interest owner's interest in the oil and/or gas (division order interest) and in addition his proportional part of the royalty (including overriding royalty) interest.

4. There is no cutoff point in terms of size of original or remaining reservoir reserves. All reservoirs that are considered to contain commercial accumulations of natural gas under existing economic and operating conditions should be reported. Even reservoirs which were at one time commercially productive but have subsequently been depleted and abandoned should be reported.

[7,860]

5. Form 1057, "Reservoir Data", will be completed for all reservoirs containing commercial accumulations of natural gas reserves. Oil reservoirs from which natural gas cannot be saved and marketed under present economic and operating conditions need not be reported. Form 1057 is a general reporting form applicable to various types of gas reserve estimates [see ITEM (51)]. It is NOT expected that every item will be filled in for any one type of reserve calculation.

6. USE CAPITAL LETTERS (UPPER CASE) FOR ALL CODES AND LABELS on Form 1057 requiring use of alphabetic characters.

   i.e. A, not a
   N, not n

7. Any numerical data items having more digits than the spaces provided will be entered on the back of Form 1057 in the available space below Item (88).

Give Item number and the data which overflows the normally provided spaces. Example:

(22) 1,001,011.7

(22) 1,001,012.

Whenever this ALTERNATE METHOD is used, leave the spaces originally provided for the Item elsewhere blank.

8. ALL NUMERIC VALUES reported must be right justified with zero fill.

   Example: a reservoir having a depth of 977 feet is reported as 00977 in the five spaces of Item (20) provided for reporting reservoir depth.

9. ALL ALPHABETIC DATA reported must be left justified leaving any unused spaces BLANK.

   Example: report the field named "Block 14" in the first eight positions of Item (15) as BLOCK 14 and leave the remaining 30 spaces to the right blank.

10. All gas volumes are to be reported at a pressure base of 14.73 psia at 60°F.

[7,861]

11. All crude oil and condensate should be reported in barrels (42 U.S. gallons) at 60°F.

12. The filings should be submitted printed or typed on the forms supplied by the Commission, or exact reproductions. (Negative photostats or thermofax copies are not acceptable).

13. For the purpose of this survey, gas reserves will be defined as the current estimated quantity of natural gas and natural gas liquids which analysis of geo-

logic and engineering data demonstrate with reasonable certainty to be recoverable in the future from known oil and gas reservoirs under existing economic and operating conditions. The existence of these reserves may have been determined by actual production completion; testing during drilling operations; or by the interpretation of cores, logs or other geological and engineering information obtained by the drilling of any type of well, including stratigraphic tests or "expendable" wells.

Prehearing Conference Exhibit No. 3

[7,862]

RESERVOIR DATA
(FPC FORM 1057)

ITEM	INSTRUCTION, CLARIFICATION, OR DESCRIPTION
(01)	38 spaces are provided for the PIPELINE PURCHASER. Skip a space to provide proper differentiation between words. If necessary, abbreviate the words "Company", "Corporation" and "Incorporated" to enable space to accommodate the name. If the gas reserves are not under a gas purchase contract, leave this item BLANK.
(02)-(14)	These items are reserved for coding by the FPC Staff; leave these items blank.
(15)	38 spaces are provided for the FIELD NAME. Skip spaces as necessary to provide proper differentiation between words. The name desired here is the field name under which production is reported to the Louisiana Conservation Commission or, if not yet producing, the field name under which production will be reported. When the field name is a Block Number, the Block Number should be listed first, followed by the name of the offshore area. For example: BLOCK 107 SHIP SHOAL AREA
(16)	38 spaces are provided for the RESERVOIR NAME. Reservoir is the definitive term of an individual hydrocarbon accumulation. Reservoirs are usually designated by a combination name which include some or all of the following components;

ITEM	INSTRUCTION, CLARIFICATION, OR DESCRIPTION

ROCK SERIES—Miocene, Pliocene, etc.
INDEX FOSSIL—Bulminella, Discorbis, etc.
GENERAL DEPTH—10,500 ft sand
ALPHABETIC—"A" Sand, "A-1" Sand, etc.
FAULT SEGMENT—Segment II, Segment A, etc.

Use the reservoir name that is commonly applied by the companies operating in the field area, however, make the name complete enough so that it can be definitely identified as a separate reservoir. Where possible, use the reservoir name under which production is reported to the Louisiana Conservation Commission or the name under which production *will be* reported.

[7,863]

Special punctuation marks (commas, periods, slashes, etc.) may not be used unless such marks constitute a significant feature of the spelling (i.e., hypenated names).

(17) Leave Item (17) blank.

(18) One space is provided for the TYPE code which identifies the type of natural gas accumulation present in the reservoir. For the purpose of this survey, Type "T", Combined Non-Associated, should not be used. REMINDER: when coding use CAPITAL LETTERS.

(19) Four spaces are provided for reporting the DATE OF RESERVOIR ESTIMATE: two spaces for the month and two spaces for the year. Each reservoir will be reported as of December 31, 1968.

ITEM	INSTRUCTION, CLARIFICATION, OR DESCRIPTION
(20)	Five spaces are provided for reporting RESERVOIR DEPTH. The depth reported should be the average vertical midpoint of the hydrocarbon accumulation in the reservoir.
(21)	Item (21) should be left blank in this survey.
(22)	Six spaces are provided for reporting PRODUCTIVE ACRES. The sixth space is a decimal value (10ths of acres) and was provided because the computations involving the use of a planimeter usually call for averaging two or more readings which almost always results in a decimal fraction. It should NOT BE INTERPRETED as implying extreme accuracy in determining productive acres. Rounding to the nearest acre is acceptable; in which case the space to the right of the decimal will be left *BLANK* to indicate rounding. The value entered here must be the one used to derive the Initial Gas In Place reported in Item (53). BEFORE COMPLETING THIS ITEM PLEASE READ THE INSTRUCTIONS FOR ITEM (53).
(23)	Four spaces are provided for reporting NET THICKNESS. The fourth space is a decimal value (10ths of feet) and was provided because the EFFECTIVE PAY SECTION of a reservoir is usually determined from averaging the values of several well logs and core samples. Consequently the net thickness has usually been reported to the FPC to the nearest tenth of a foot

but this fact has never been and should NOT BE INTERPRETED as implying extreme accuracy

ITEM	INSTRUCTION, CLARIFICATION, OR DESCRIPTION

in determining the net thickness (effective pay) of a natural gas reservoir. Rounding to the nearest foot is acceptable; in which case the space to the right of the decimal will be left *blank* to indicate rounding.

(24) Nine spaces are provided for reporting ACRE-FEET. The ninth space is a decimal value (10ths of Acre-Ft.) and is provided for the reasons given in (22) and (23) above. THE DATA DESIRED HERE IS THE PRODUCT OF THE VALUES CONTAINED IN ITEMS (22) and (23). If rounding was employed in Items (22) and (23) it will also be employed here; in which case the space to the right of the decimal will be left *blank* to indicate rounding.

(25) Three spaces are provided for reporting POROSITY. The third space is a decimal value (10ths of a percent) which is provided to allow the inclusion of fractional values usually encountered when making a porosity determination from several different data sources. Rounding to the nearest percent is acceptable; in which case the space to the right of the decimal will be left *blank* to indicate rounding. The value desired here is your best estimate of the average porosity of the reservoir which you have derived from the basic data available to your company. IT IS SPECIFICALLY TO BE THE VALUE USED IN DERIVING GAS RESERVES REPORTED IN ITEM (53).

Special Note for Pressure Decline Estimates

It is acceptable to report porosity as derived from, or "backed out" of, Pressure Decline curves if

ITEM	INSTRUCTION, CLARIFICATION, OR DESCRIPTION

your reservoir reserves have been estimated by the performance method. IF THIS ALTERNATE METHOD IS USED, ITEM (26) WILL BE CODED "3" for *Estimated* and ITEM (51) WILL BE CODED "2" for *Pressure Decline Calculation.*

(26) Leave Item (26) blank.

(27) Three spaces are provided for reporting CONNATE WATER. The third space is a decimal value (10ths of a percent), which is provided to allow the inclusion of fractional values usually

[7,865]

encountered when making a connate water determination from several different data sources. Rounding to the nearest percent is acceptable; in which case the space to the right of the decimal will be left *blank* to indicate rounding. The value desired is your best estimate of the average connate water of the reservoir which you have derived from the basic data available to your company. IT IS SPECIFICALLY TO BE THE VALUE USED IN DERIVING THE GAS RESERVES REPORTED IN ITEM (53).

Special Note for Pressure Decline Estimates

It is acceptable to report connate water as derived from, or "backed out" of, Pressure Decline Curves, if your reservoir reserves have been estimated by the performance method. IF THIS ALTERNATE METHOD IS USED, ITEM (28) WILL BE CODED "3" for *Estimated* and ITEM (51) WILL BE CODED "2" for *Pressure Decline Calculation.*

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ITEM	INSTRUCTION, CLARIFICATION, OR DESCRIPTION
(28)	Leave Item (28) blank.
(29)	Leave Item (29) blank.
(30)	Leave Item (30) blank.
(31)	Leave Item (31) blank.
(32)	Leave Item (32) blank.
(33)	Leave Item (33) blank.
(34)	Four spaces are provided for reporting TEMPERATURE. Specifically, the VALUE REPORTED MUST BE THE *EXACT EQUIVALENT BY TYPE* of THE VALUE USED IN DERIVING THE GAS RESERVES REPORTED IN ITEM (53); i.e. if degrees Rankine were used in your volumetric calculations the value given here may be degrees Centigrade, Fahrenheit, or Kelvin, but if so, that value when converted to degrees Rankine must yield a value identical to the Rankine value used in your calculations. The coding of Item (35) will identify the type of temperature value reported.

Special Note for Pressure Decline Estimates

It is acceptable to report temperatures as derived from, or "backed out" of, Pressure Decline Curves, if your reservoir reserves have been estimated by the performance method. IF THIS ALTERNATE METHOD IS USED, ITEM (51) WILL BE CODED "2" for *Pressure Decline Calculation.*

ITEM	INSTRUCTION, CLARIFICATION, OR DESCRIPTION

(35) One space is provided for numerically coding the TEMPERATURE TYPE classification of the temperature value reported in Item (34). Code "3", *Absolute, Type Unspecified,* should not be used. This code is reserved for special computer correllation and is not applicable to your reservoir temperatures.

(36) Five spaces are provided for reporting the INITIAL PRESSURE (PSIA) of the reservoir. Specifically, the VALUE REPORTED MUST BE THE VALUE USED IN DERIVING THE GAS RESERVES REPORTED IN ITEM (53). The coding of Item (37) will identify the type pressure reported.

Special Note for Pressure Decline Estimates

It is acceptable to report INITIAL PRESSURE (PSIA) as derived from, or "backed out" of, Pressure Decline Curves if your reservoir reserves have been estimated by the performance method. IF THIS ALTERNATE METHOD IS USED, ITEM (51) WILL BE CODED "2" for *Pressure Decline Calculation.*

(37) One space is provided for numerically coding TYPE PRESSURE. This item related to Item (36) *Initial Pressure,* Item (38), *Current Pressure,* and Item (39) *Terminal Pressure*; therefore ALL PRESSURES REPORTED ON AN INDIVIDUAL FORM 1057 WILL BE THE SAME TYPE. For this project, Code "3", *Wellhead flowing,* and Code "4", *Bottom Hole Flowing,* should NOT be used.

ITEM	INSTRUCTION, CLARIFICATION, OR DESCRIPTION
(38)	Five spaces are provided for reporting CURRENT PRESSURE (PSIA). UNLESS the reported reservoir reserves are based on a PRESSURE DECLINE ESTIMATE, this Item NEED NOT BE REPORTED. [SEE INSTRUCTIONS ON TYPE PRESSURE REPORTED IN ITEM (37) ABOVE].

[7,867]

(39)	Five spaces are provided for reporting TERMINAL PRESSURE (PSIA). It is true that this is a judgement factor and since economic forces affect this over time periodic updating can be expected. WHAT IS DESIRED HERE IS YOUR CURRENT JUDGEMENT AFTER EVALUATION OF EXISTING ECONOMIC CIRCUMSTANCES [SEE INSTRUCTIONS ON TYPE PRESSURE REPORTED IN ITEM (37) ABOVE].
(40)	Leave Item (40) blank.
(41)	Three spaces are provided for reporting INITIAL Z to the nearest hundredth. If more spaces past the decimal are needed then the ALTERNATIVE METHOD for reporting numerical data set forth in GENERAL INSTRUCTION 7 will be used. *Special Note for Pressure Decline Estimates* It is acceptable to report INITIAL Z as derived from, or "backed out" of, Pressure Decline Curves if your reservoir reserves have been estimated by the performance method. IF THIS ALTERNATIVE METHOD IS USED, ITEM (51) WILL BE CODED "2" for *Pressure Decline Calculation.*

ITEM	INSTRUCTION, CLARIFICATION, OR DESCRIPTION
(42)	Three spaces are provided for reporting CURRENT Z to the nearest hundredth. THIS ITEM NEED NOT BE REPORTED UNLESS YOU ARE REPORTING A PRESSURE DECLINE ESTIMATE. For those reporting this Item, the ALTERNATE METHOD for reporting numerical data as set forth in GENERAL INSTRUCTION 7 will be used IF, as some participants have indicated, more spaces past the decimal are needed for the value to be reported. The *Special Note for Pressure Decline Estimates* in Item (41) above IS ALSO APPLICABLE TO THIS ITEM.
(43)	Three spaces are provided for reporting TERMINAL Z to the nearest hundredth. This Item is recognized as being a judgement factor and that it has a direct bearing on the recovery factor. WHAT IS DESIRED HERE IS THE ESTIMATED TERMINAL Z YOU MAY HAVE USED IN DETERMINING THE RECOVERY FACTOR IN ITEM (54). For those reporting this Item, the ALTERNATE METHOD for reporting numerical data as set forth in GENERAL INSTRUCTION 7 will be used IF more spaces past the decimal are needed for the value to be reported.

[7,868]

The Special Note for *Pressure Decline Estimates* in Item (41) above is ALSO APPLICABLE TO THIS ITEM.

ITEM	INSTRUCTION, CLARIFICATION, OR DESCRIPTION
(44)	Six spaces are provided for reporting the average GAS/OIL RATIO (GOR) OR GAS/LIQUID RATIO (GLR) at *original reservoir* conditions in MCFs of natural gas per reservoir barrel of oil or condensate liquid. The information requested here is the ratio of the liberated gas to the retained liquid through normal lease separation equipment down to the base pressure for which the gas reserves are calculated. If these volumes were measured at higher operating pressures, extrapolations down to the base pressure are permissable. The information sought here is the volume of gas per barrel of liquid in place in the reservoir and stated at base condition measurements.
(45)	Three spaces are provided for reporting the INITIAL FORMATION VOLUME FACTOR (FVF) at original reservoir conditions to the nearest hundredth. The information sought here is the relationship of the volume occupied by a given quantity of oil at initial reservoir conditions as compared to the volume occupied by the same quantity of oil at stock tank conditions. The FVF may have been determined by the analysis of a bottomhole sample, a wellhead sample, estimated from a gas-oil ratio or by other means. If several options are available, the reserve analyst should use his judgement as to which FVF best represents this volume relationship. The ALTERNATE METHOD for reporting numerical data as set forth in GENERAL INSTRUCTION 7 will be used IF more spaces past the decimal are needed for the value to be reported. UNLESS the reported re-

ITEM	INSTRUCTION, CLARIFICATION, OR DESCRIPTION

serves are from a DISSOLVED GAS RESERVOIR, this Item NEED NOT BE REPORTED.

(46) Six spaces are provided for reporting the initial number of RESERVOIR BARRELS PER ACRE/FOOT in place at original reservoir conditions. UNLESS the reported reserves are from a DISSOLVED GAS RESERVOIR, this Item NEED NOT BE REPORTED.

[7,869]

(47) Leave Item (47) blank.

(48) Three spaces are provided for reporting the TOTAL CURRENTLY PRODUCING WELLS on the lease which are completed in and are producing from the reservoir being reported. This information should be as of the date of the reserve estimate (Item 19).

(49) Ten spaces are provided for reporting CUMULATIVE OIL PRODUCTION in Stock Tank Barrels. UNLESS the reported reserves are based on a MATERIAL BALANCE ESTIMATE, this Item NEED NOT BE REPORTED. The data reported here MUST BE THE VALUE for Cumulative Oil Production USED IN YOUR MATERIAL BALANCE CALCULATION of the reserves reported in Item (53). Report only the cumulative oil production from the reservoir from wells actually bottomed under the lease. Do not attempt to allocate production from a reservoir to the various leases that contain the reservoir.

ITEM	INSTRUCTION, CLARIFICATION, OR DESCRIPTION
(50)	Ten spaces are provided for reporting CUMULATIVE WATER PRODUCTION in barrels. UNLESS the reported reserves are based on a MATERIAL BALANCE ESTIMATE, this Item NEED NOT BE REPORTED. The data reported here MUST BE THE VALUE for Cumulative Water Production USED IN YOUR MATERIAL BALANCE CALCULATION of the reserves reported in Item (53). Report only the cumulative water production from the reservoir from wells actually bottomed under the lease. Do not attempt to allocate production from a reservoir to the various leases that contain the reservoir.
(51)	One space is provided for numerically coding the TYPE OF CALCULATION used to derive the gas reserves reported in Item (53). Code "4", *Nominal*, is intended to be used in cases where production has exceeded the original volumetric estimate based on the measured physical factors and the reservoir is expected to continue to produce a nominal amount of gas. Code "5", *Time Decline*, is sometimes called Production Performance because it is an estimate obtained by plotting cumulative production over time. Such an estimate may or may not agree with a volumetric estimate based on such physical

[7,870]

factors as are available for the reservoir. This method is usually employed when one or more of the physical factors required for a volumetric calculation are not available. If Item (51) is indi-

ITEM	INSTRUCTION, CLARIFICATION, OR DESCRIPTION

cated as "2", *Pressure Decline*, certain information in Part B is still desirable. Specifically, Items (20), (34), (35), (36), (37), (38), (39), (41), (42), (43), (44) and (48) will be needed for either calculations or for statistical compilations.

(52) One space is provided for numerically coding the PRESSURE BASE (PSIA 60°F.). The official government pressure base is 14.73 psia at 60° Fahrenheit (Code "7") and should be used for all volumes of gas reported in the Form 1057.

(53) Seven spaces are provided for reporting the INITIAL GAS IN PLACE IN MMCF in that portion of the reservoir underlying the lease being reported.

(54) Three spaces are provided for reporting the RECOVERY FACTOR in decimal fractions, NOT percents. As in Item (39), this is a judgement factor and since economic forces affect this over time periodic updating can be expected. What is desired here is your current judgement after evaluation of existing economic circumstances. Since this is the AVERAGE recovery factor it MUST agree with the data reported in Item (53). That is, it will either be the average for the total reservoir, or the average of that portion of the reservoir which underlies the lease being reported.

(55) Seven spaces are provided for reporting the TOTAL ORIGINAL RECOVERABLE WET GAS IN MMCF. The value to be entered here is THE PRODUCT OF ITEM (53) AND ITEM (54).

ITEM	INSTRUCTION, CLARIFICATION, OR DESCRIPTION
(56)	Two spaces are provided for reporting average SHRINKAGE in decimal fractions, NOT percents. IF THE GAS IN PLACE IS PIPELINE QUALITY GAS this value can be ZERO and there is no distinction between wet and dry gas as it relates to this Item. IN ALL OTHER CASES, the value desired here is that which accounts for the difference in the volume of gas produced at the wellhead and that which is available to the pipeline purchaser at the sales metering station under the current

[7,871]

operating conditions. In the case of reservoirs that are not as yet productive, certain judgements will have to be made, based on current economic and other considerations, as to the probable operating conditions. Since this is the AVERAGE shrinkage factor it MUST agree with the data reported in Item (53). That is, it will either be the average for the total reservoir, or the average of that portion of the reservoir which underlies the lease being reported.

(57) Seven spaces are provided for reporting cumulative wet gas production in MMCF through the date of the reserve estimate. (Item 19). If production records are maintained only on a dry gas basis, record the dry gas production in these spaces and footnote Item (57) at the bottom of the form to show that this is dry gas production. If dry gas is reported in Item (57), then Items (58), (59), (61), and (63) should be left blank.

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ITEM	INSTRUCTION, CLARIFICATION, OR DESCRIPTION
(58)	Six spaces are provided for reporting CUMULATIVE SHRINKAGE in MMCF through the date of the reserve estimate (Item 19). The value desired here is the product of Item (57) multiplied by Item (56).
(59)	Seven spaces are provided for reporting TOTAL REMAINING RECOVERABLE WET GAS in MMCF as of the date of the reserve estimate (Item 19). The value desired here is the difference between Item (55) and Item (57).
(60)	Leave Item (60) blank.
(61)	Seven spaces are provided for reporting the TOTAL REMAINING RECOVERABLE DRY GAS in MMCF as of the date of the reserve estimate (Item 19). The value desired here is the product of Item (59) multiplied by [1—(Item (56))].
(62)	Leave Item (62) blank.
(63)	Seven spaces are provided for reporting net REMAINING RECOVERABLE WET GAS RESERVES as of the date of the reserve estimate (Item 19). The fact of the dedication will be determined to the response to Item (1).

[7,872]

(64)	Leave Item (64) blank.
(65)	Leave Item (65) blank.
(66)	26 spaces are provided for reporting the name of the LEASE OPERATOR of the specific lease for which the particular reservoir reserve analysis is

ITEM	INSTRUCTION, CLARIFICATION, OR DESCRIPTION

made. This name should be the same as is shown on the well record and production forms filed with the Louisiana Conservation Commission. Only one operator is to report the reserves for each reservoir under each lease. The reserves are to represent 100% of the reserves in the reservoir under each lease.

(67) This item, OPERATOR CODE, is to be completed using the code supplied by the FPC Staff to each producer (operator) respondent.

(68) In the event that the lease operator or his designee is reporting for the total interest and there is more than one pipeline purchaser from the reported reservoir on the reported lease, the additional purchaser(s) are to be reported in Items (68) and (70). These pipeline purchasers will be reported in addition to the principal purchaser reported in Item (1).

(69) Leave Item (69) blank.

(70) See instructions at Item (68).

(71) Leave Item (71) blank.

(72) Two spaces are provided for the OFFSHORE AREA CODE. The coding to be used here is contained in Attached Appendix A, Part 1.

(73) This item should contain the numbers 2, 3 or 4 to designate the OFFSHORE ZONE in which the lease being evaluated is located. For the purpose of this survey, the zones are defined as the offshore area described as Zones 2, 3 and 4 in the Interim Agreement between the United States and

ITEM	INSTRUCTION, CLARIFICATION, OR DESCRIPTION

the State of Louisiana, dated October 12, 1956, as amended, excluding lands awarded to the State of Louisiana by Supplemental Decree of the Supreme Court of the United States entered December 31, 1965 (382 U.S. 288).

[7,873]

In the event, that the lease is traversed by a boundary line separating two different zones, this space should contain the number of the zone containing the largest portion of the *surface acres* in the lease.

(74) There are 38 spaces provided for the name of STATE and OFFSHORE AREA. For the purpose of this survey, the first nine spaces should contain the name LOUISIANA. A space should be skipped and the last 28 spaces are provided for the name of the AREA, (i.e. WEST CAMERON, MAIN PASS, etc.). It is not necessary to include the words AREA, SOUTH ADDITION, etc. as a part of the Area name.

(75) Three spaces are provided for the Area BLOCK NUMBER. This is to be the Area Block Number in which the lease and reservoir being evaluated is located, and is not necessarily the same Block Number for which the field is named.

(76) There are 4 spaces provided for the Federal Oil and Gas Lease Serial Number. This is the OCS "G" Number shown on the face of the oil and gas lease under which drilling and producing operations are being conducted.

ITEM	INSTRUCTION, CLARIFICATION, OR DESCRIPTION
(77)	Four spaces are provided for the month and year of the reservoir discovery on the lease. This should be the month, as near as possible, that the reservoir was determined to be productive under the lease by actual production completion; testing during drilling operations; or by the interpretation of cores, logs or other geological information.
(78)	Three spaces are provided for the total number of wells on the lease, completed for production in the reservoir being evaluated, that are shut-in as a regular status because of one of the reasons given in ITEM (79) below.
(79)	This space is provided to explain the reason for the shut-in status of the number of wells reported in ITEM (78) above. In the event that the wells are shut-in for some other reason than those cited on the form, leave this space BLANK.

(80)	These spaces are provided for the name of the working interest owner under the lease when each owner is reporting his interest separately. (See instruction "3" in the General Instructions).
(81)	Six spaces are provided for a five place decimal equivalent interest of the owner reporting in Item (80) above. This decimal equivalent interest will be the combined total of the owner's interest and his proportional part of the royalty interest.
(82)	Four spaces are provided for the specific gravity of the gas (air—1.000). Three spaces are provided for 3 digits to the right of the decimal.

ITEM	INSTRUCTION, CLARIFICATION, OR DESCRIPTION
(83)	One space is provided to indicate the location of the gas sample. Indicate fullstream with 1 and after separation with 2.
(84)	Six spaces are provided for GOR in cubic feet per barrel at 14.73 psia and 60°F.
(85)	Three spaces are provided for condensate gravity in degrees API. One space is provided to the right of the decimal. GOR and condensate gravity are to be furnished only when the gas sampled is not a full stream.
(86)	Four spaces are provided for the mole fraction of carbon dioxide.
(87)	Four spaces are provided for the mole fraction of nitrogen.
(88)	Four spaces are provided for the mole fraction of hydrogen sulfide.

Prehearing Conference Exhibit No. 3

[7,875]

APPENDIX A

Part 1

LOUISIANA OFFSHORE AREA	OFFSHORE AREA CODE
West Cameron Area	01
East Cameron Area	02
Vermilion Area	03
South Marsh Island Area	04
Eugene Island Area	05
Ship Shoal Area	06
South Pelto Area	07
Bay Marchand Area	08
South Timbalier Area	09
Grand Isle Area	10
West Delta Area	11
South Pass Area	12
Main Pass Area	13
Breton Sound Area	14
Chandeleur Sound Area	15

Part 2

Offshore Producing Area Code	99
State of Louisiana Code	17
Offshore Zone Number	as designated
Offshore Block Number	as designated

Example:

99	17	06	4	145
Offshore	Louisiana	Ship Shoal	Zone	Block

Docket No. RP69-1
Phase I
(DRC No. 1)
Hearing Exhibit 2
Schedule 1

NATIONAL FUEL GAS COMPANY

Annual Requirements and Supply
Mcf @ 14.73 psia
Actual for 1969 - Estimated for 1970 - 1980

No.	Particulars	1969 (1)	1970 (2)	1971 (3)	1972 (4)	1973 (5)	1974 (6)	1975 (7)	1976 (8)	1977 (9)	1978 (10)	1979 (11)	1980 (12)	1981 (13)
	Column 1													
1	Gas Requirements													
2	Firm													
3	Residential	114,521	119,300	121,900	123,700	125,900	128,100	130,200	132,800	134,900	137,100	139,400	141,800	
4	Commercial	29,294	31,100	33,100	35,500	38,000	40,600	42,800	45,000	47,200	49,300	51,400	53,500	
5	Industrial	69,583	78,100	83,400	86,600	89,800	93,000	96,200	99,300	102,400	105,400	108,400	111,400	
6	Sales for Resale	2,628	2,900	2,900	2,900	3,100	3,100	3,200	3,300	3,400	3,600	3,800	4,000	
7	Underground Storage - Net	4,831	2,400	2,300	900	4,400	3,300	2,700*	2,700*	2,700*	2,700*	2,700*	2,700*	
8	Other	6,845	4,600	5,300	5,300	5,800	5,300	5,300	5,400	5,600	5,700	5,900	6,000	
9	Total	226,304	238,400	248,900	254,900	266,900	273,200	280,400	288,300	296,100	303,800	311,600	319,600	
10	Gas Supply													
11	Own Production													
	a. Appalachian Area (NY & Pa.)	8,211	8,100	7,770	7,430	7,060	6,700	6,350	6,010	5,670	5,330	4,990	4,650	
12	Purchases from Independent Producers													
	a. Shell Oil (Sheridan Field, Texas)	18,151	18,151	18,151	18,201	18,151	15,118	0	0	0	0	0	0	
	b. Appalachian Area	6,552	5,400	6,700	4,700	4,200	3,800	3,500	3,300	3,000	2,800	2,500	2,300	
13	Purchases from Pipelines Contracted for													
	a. Tennessee Gas Pipeline Co.	102,269	114,355	105,733	106,033	105,733	105,733	105,733	106,033	105,733	105,733	105,733	106,033	
	b. Texas Eastern Transmission Co.	27,977	28,519	28,518	28,596	28,519	28,519	28,519	28,596	28,519	28,519	28,519	28,596	
	c. Consolidated Gas Supply Co.	31,165	31,279	31,437	31,724	31,752	31,913	32,075	32,236	32,399	32,561	32,723	32,986	
	d. Transcontinental Gas Pipeline Co.	9,261	9,287	9,287	9,311	9,287	9,287	9,287	9,311	9,287	9,287	9,287	9,311	
	e. Manufacturers Light & Heat	3,237	7,373	7,373	7,393	7,373	7,373	7,373	7,393	7,373	7,373	7,373	7,393	
	f. Valley Gas Transmission Co.	12,706	12,706	12,706	12,741	12,706	12,706	12,706	12,741	12,706	12,706	12,706	12,741	
	g. Manufactured Gas Purchased	8,619	8,400	8,400	0	0	0	0	0	0	0	0	0	
14	Total	228,204	245,570	236,075	226,119	224,761	221,149	205,543	205,713	204,687	204,309	203,831	204,000	
15	Additional Supply Needed		(7,170)	12,825	28,481	41,739	52,051	74,857	82,588	91,413	99,491	107,769	115,600	

* Projected Storage Development.

51 e

Hearing Exhibit No. 2

[8,005]

[8,005]

[8,006]

Hearing Exhibit No. 2

[8,006]

NATIONAL FUEL GAS COMPANY

Peak Day Gas Requirements and Supply
Mmcf @ 14.73 psia
Actual for 1969 - Estimated for 1970 - 1980

Docket No.
Phase I
(NDC No. 1,
Hearing Exhibit 2
Schedule 2

Line No.	Particulars Column 1	1969 (2)	1970 (3)	1971 (4)	1972 (5)	1973 (6)	1974 (7)	1975 (8)	1976 (9)	1977 (10)	1978 (11)	1979 (12)	1980 (13)
1	Gas Requirements												
2	Firm												
3	Residential	834	960	969	1,005	1,035	1,063	1,091	1,119	1,147	1,175	1,203	1,231
4	Commercial	188	216	224	229	236	244	252	260	268	276	284	292
5	Industrial	230	268	269	277	283	287	295	303	311	319	327	335
6	Sales for Resale	22	21	22	22	22	22	22	22	22	22	22	22
7	Underground Storage - Net	0	0	0	0	0	0	0	0	0	0	0	0
8	Other	21	31	33	37	38	41	44	47	50	53	56	59
9	Total	1,296	1,474	1,533	1,570	1,614	1,657	1,704	1,751	1,798	1,845	1,892	1,939
10	Gas Supply												
11	Own Production												
	a. Appalachian Area	30	27	27	24	23	21	19	17	15	13	11	9
12	Purchases from Independent Producers												
	a. Shell Oil (Sheridan Field, Texas)	80	80	80	80	80	80	0	0	0	0	0	0
	b. Appalachian Area	20	16	21	14	13	13	13	13	10	10	10	10
13	Purchases from Pipelines Contracted for (List Each Pipeline)												
	a. Tennessee Gas Pipeline Co.	289	330	287	287	287	287	287	287	287	287	287	287
	b. Texas Eastern Transmission Co.	80	78	78	78	78	78	78	78	78	78	78	78
	c. Consolidated Gas Supply Co.	167	204	207	207	208	210	211	213	213	214	215	216
	d. Transcontinental Gas Pipeline Co.	24	25	25	25	25	25	25	25	25	25	25	25
	e. Manufacturers Light & Heat	10	20	20	20	20	20	20	20	20	20	20	20
	f. Valley Gas Transmission Co.	35	35	35	35	35	35	35	35	35	35	35	35
	g. Manufactured Gas Purchased	23	26	26	0	0	0	0	0	0	0	0	0
	Underground Storage	268	673	757*	760*	760*	760*	760*	760*	760*	760*	760*	760*
14	Total	1,296	1,474	1,533	1,500	1,499	1,498	1,447	1,448	1,443	1,443	1,441	1,440
15	Additional Supply Needed	0	0	0	70	115	159	257	305	355	403	451	499

*Underground storage (withdrawals) are dependent upon receipt of "Additional Supply Needed". Future development not yet finalized.

Docket No. AR69-1
Phase 1
(NDC No. 1)
Hearing Exhibit 2
Schedule 3

NATIONAL FUEL GAS COMPANY

Actual Peak Day and Annual Sales Volumes
MMcf @ 14.73 psia
1961 - 1969

Line No.	Particulars Column 1	Jan 31, 1961 (2)	Jan 24 1963 (3)	Jan 13 1964 (4)	Feb 3 1965 (5)	Jan 28 1966 (6)	Feb 25 1967 (7)	Feb 21 1968 (8)	Jan 1 1969 (9)
1	Peak Day Requirements								
2	Residential	676	781	689	756	795	760	848	834
3	Commercial	134	177	140	174	185	171	191	188
4	Industrial	154	172	168	206	209	203	229	230
5	Sales for Resale	14	19	18	20	21	20	21	23
6	Other	18	22	24	25	24	30	27	21
7	Total	996	1,171	1,039	1,183	1,234	1,184	1,316	1,296
8	Annual Requirements								
9	Residential	99,247	99,219	103,544	106,347	107,688	110,741	113,701	114,521
10	Commercial	18,318	19,401	20,855	22,367	23,922	25,871	27,356	29,294
11	Industrial	39,105	43,242	46,636	52,224	55,195	57,073	62,502	69,885
12	Sales for Resale	2,453	2, 58	2,466	2,452	2,984	3,033	2,927	2,828
13	Other	4,778	4,967	5,481	5,505	5,160	4,738	7,937	7,146
14	Total[1]	139,901	169,493	175,972	188,895	195,149	201,456	213,413	223,674

1/ Increases in current and noncurrent storage inventories not included.

53 e

Hearing Exhibit No. 2

[8,007]

[8,007]

Exhibit No. 3

[8,008]

Docket No. AR69-1

Witness: Simpson

Date _____

CONSUMERS POWER COMPANY

GAS MARKET AND SUPPLY DATA

CONSUMERS POWER COMPANY

Miscellaneous Customer Data 1/

Line No.	Particulars Column 1	Firm Residential Heating (2)	Residential Non-Heating (3)	Commercial (4)	Industrial (5)	Interruptible (6)	Total (7)
1	Number of Customers @ 12/31/69	675,851	93,122	55,442	5,591	4	830,010
2	1969 Retail Sales in Mcf @14.73 psia	129,060	3,997	58,485	87,969	258	279,769
3	Annual Use Per Customer (MCF)	191	43	1,055	15,734	64,500	337
4	1969 Retail Revenue (000's omitted)	$133,776	$ 6,098	$ 47,675	$ 49,005	$ 116	$236,670
5	Revenue Per Mcf ($ per MCF)	1.04	1.53	.82	.56	.45	.85

1/ These data may be combined for those companies under a common ownership.

55e

[8,009]

Exhibit No. 3

Schedule 1
Sheet 1 of 2

[8,009]

Exhibit No. 3

[8,010]

Schedule 1
Sheet 2 of 2

CONSUMERS POWER COMPANY

Miscellaneous Statistical Data 1/

Line No.	Particulars Column 1	Number or Amount (2)
1	As of December 31, 1969	
2	Number of Gas Utility Employees	4,756
3	Gas Plant in Service - Gross	$ 18,044,744
4	Production	$121,704,364
5	Storage	$119,991,155
6	Transmission	$429,359,719
7	Distribution	$ 42,800,456
8	Other	3,000,000
9	Population of Area Served	579
10	Number Incorporated Communities Served	
11	Miles of Gas Mains	1,200
12	Transmission	15,314
13	Distribution	
14	Calendar Year 1969	
15	Revenue Other Than Gas	$307,599,678
16	Electric	$ 1,239,386
17	Other	
18	Cost of Purchases from Independent Producers (Show for Each FPC Pricing Area)	
	a. Miscellaneous Michigan Production	$ 4,635,415
	b.	
	c.	
19	Cost of Pipeline Purchases (List Each Pipeline)	
	a. Trunkline Gas Co.	$ 70,399,838
	b. Panhandle Eastern Pipeline Co.	$ 29,250,359
	c.	
	d.	
	e.	

1/ These data may be combined for those companies under a common ownership. Includes subsidiary Michigan Gas Storage Co.

Exhibit No. 3

CONSUMERS POWER COMPANY 2/

Annual Requirements and Supply
Mcf @ 14.73 psia
Actual for 1969 - Estimated for 1970 - 1982

Line No.	Particulars Column 1	1969 (2)	1970 (3)	1971 (4)	1972 (5)	1973 (6)	1974 (7)	1975 (8)	1976 (9)	1977 (10)	1978 (11)	1979 (12)	1980 (13)
1	Gas Requirements												
2	Firm												
3	Residential	133,057	136,881	144,100	151,400	158,800	166,500	173,790	180,000	187,000	194,000	201,000	209,000
4	Commercial	57,589	65,874	72,300	82,600	93,000	106,100	118,000	125,000	132,000	139,000	146,000	153,000
5	Industrial	80,164	90,701	112,600	112,400	127,900	140,800	153,800	159,500	173,300	183,600	193,600	206,600
6	Power Generation	6,361	14,100	4,900	4,900	4,900	4,900	4,900	4,900	4,900	4,900	4,900	4,900
7	Interruptible												
8	Commercial & Industrial	197	3,700	12,600	31,600	36,600	41,600	46,600	50,600	54,600	59,600	63,600	67,600
9	Power Generation	61	300	5,400	4,400	4,400	4,400	3,400	3,400	3,400	2,400	2,400	2,400
10	Sales for Resale 1/	1,032	1,000	700	-	-	-	-	-	-	-	-	-
11	Sales for Resale to UGI Members	960	-	-	-	-	-	-	-	-	-	-	-
12	Underground Storage - Net.	19,831	13,110	5,000	5,000	5,000	12,000	-	-	-	-	-	-
13	Other - Use and Loss	11,408	13,033	14,805	15,115	15,065	16,310	17,340	18,390	19,300	20,350	21,860	23,160
14	Total	307,000	336,779	371,805	407,415	447,465	492,110	518,630	545,790	574,300	604,150	635,360	668,660
15	Gas Supply												
16	Own Production												
	(Show for Each Producing Area)												
	a. Mic Michigan Production	6,032	9,185	6,600	6,600	1,500	-	-	-	-	-	-	-
	b.												
	c.												
17	Purchases from Independent Producers												
	(Show for Each Producing Area)												
	a. Mic Michigan Production	9,945	9,999	9,690	9,690	9,690	9,690	9,690	9,690	9,690	9,690	9,690	9,690
	b.												
	c.												
18	Purchases from Pipelines Contracted for (List each Pipeline)												
	a. Trunkline Gas Company	197,826	225,100	258,390	276,085	288,875	288,875	288,875	283,690	288,875	288,875	288,875	283,690
	b. Panhandle Eastern Pipeline Co.	92,547	92,535	92,535	92,655	92,535	92,535	92,535	92,655	92,535	92,535	92,535	92,655
	c.												
19	Other Sources (List each)												
	a.												
	b.												
	c.												
20	Total	307,000	336,779	367,335	384,930	396,560	389,060	389,060	386,955	389,060	389,060	389,060	386,955
21	Additional Supply Needed	-	-	4,470	22,485	50,905	103,050	129,570	158,835	185,240	215,090	246,300	281,705

1/ Exclude from Line 10 sales to non-affiliated UGI members. Such sales, if any, should be shown on Line 11. (See List Attached).
2/ Includes subsidiary Michigan Gas Storage Co.

[8,012]

57 e

[8,012]

Schedule 2
Sheet 2 of 3

CONSUMERS POWER COMPANY 2/

Peak Day Gas Requirements and Supply
Mcf @ 14.73 psia
Actual for 1969 - Estimated for 1970 - 1980

Line No.	Particulars Column 1	1969 (2)	1970 (3)	1971 (4)	1972 (5)	1973 (6)	1974 (7)	1975 (8)	1976 (9)	1977 (10)	1978 (11)	1979 (12)	1980 (13)
1	Gas Requirements												
2	Firm												
3	Residential	986	1,082	1,095	1,145	1,207	1,256	1,319	1,370	1,428	1,480	1,536	1,598
4	Commercial	417	475	550	629	714	827	904	991	1,079	1,098	1,111	1,126
5	Industrial	344	447	598	697	797	865	925	1,082	1,089	1,161	1,248	1,328
6	Power Generation	6	70	181	181	181	181	181	181	181	181	181	181
7	Interruptible												
8	Commercial & Industrial	-	16	-	-	-	-	-	-	-	-	-	-
9	Power Generation	-	1	-	-	-	-	-	-	-	-	-	-
10	Sales for Resale 1/	14	10	80	-	-	-	-	-	-	-	-	-
11	Sales for Resale to UGI Members	-	14	-	-	-	-	-	-	-	-	-	-
12	Other - Use and Loss	88	59	71	74	77	76	82	85	89	108	106	110
13	Total	1,735	2,074	2,569	2,716	2,979	3,188	3,411	3,609	3,789	3,928	4,176	4,373
14	Gas Supply												
15	Gas Production												
	(Show for each producing area)												
	a. Mlss Michigan Production	15	83	18	18	11	-	-	-	-	-	-	-
	b.												
	c.												
16	Purchases from Independent Producers												
	(Show for each producing area)												
	a. Mlss Michigan Production	88	89	89	89	89	89	89	89	89	89	89	89
	b.												
	c.												
17	Purchases from Pipelines Contracted												
	for (List each Pipeline)												
	a. Trunkline Gas Company	585	601	700	730	775	775	775	775	775	775	775	775
	b. Panhandle Eastern Pipeline Co	161	145	120	120	120	120	120	120	120	120	120	120
	c.												
18	Other Sources (List Each)												
	a. Underground Storage	1,006	1,880	1,732	1,749	1,904	2,009	2,214	2,225	2,265	2,306	2,358	2,401
	b.												
	c.												
19	Total	1,735	2,074	2,569	2,666	2,899	3,013	3,198	3,199	3,189	3,838	3,876	3,925
20	Additional Supply Needed	-	-	-	50	100	175	300	450	600	750	900	1,050

1/ Exclude from Line 10 sales to non-affiliated UGI members. Such sales, if any, should be shown on Line 11. (See list attached).
2/ Includes subsidiary Michigan Gas Storage Company

CONSUMERS POWER COMPANY 2/

Actual Peak Day Requirements and Actual Annual Requirements
Base @ 14.73 psia
1958 - 1969

Schedule 2
Sheet 3 of 3

Line No.	Particulars Column 1	1958 (2)	1959 (3)	1960 (4)	1961 (5)	1962 (6)	1963 (7)	1964 (8)	1965 (9)
1	Actual Peak Day Requirements								
2	Firm								
3	Residential	599	668	611	698	883	836	831	906
4	Commercial	199	254	213	257	325	288	354	417
5	Industrial	171	197	238	304	300	299	357	342
6	Power Generation	8	1	1	1	1	1	6	6
7	Interruptible								
8	Commercial & Industrial								
9	Power Generation								
10	Sales for Resale 1/	-	11	10	10	10	10	10	14
11	Sales to UGI Members	-	-	-	-	-	4	6	-
12	Other - Use and Loss	14	16	13	13	16	19	23	26
13	Total	992	1,141	1,070	1,279	1,477	1,461	1,691	1,735
14	Actual Annual Requirements								
15	Firm								
16	Residential	79,787	89,738	91,945	108,660	110,932	119,908	128,472	133,057
17	Commercial	25,249	27,767	30,913	35,903	41,088	47,376	51,696	57,989
18	Industrial	37,040	41,508	47,336	57,051	63,374	67,569	73,773	80,164
19	Power Generation	1,015	181	119	577	825	516	570	8,361
20	Interruptible								
21	Commercial & Industrial	-	-	-	-	-	-	-	197
22	Power Generation	-	-	-	-	-	-	-	61
23	Sales for Resale 1/	-	1,035	998	1,004	998	1,001	1,001	1,038
24	Sales to UGI Members	2,519	-	842	613	-	1,221	2,619	960
25	Other - Use and Loss	5,118	8,326	4,927	9,317	11,306	12,870	14,578	11,408
25A	Other - Underground Storage	3,512	9,564	8,782	973	-	787	9,703	13,831
26	Total	154,240	178,859	185,860	208,098	227,863	251,247	276,746	307,000

1/ Exclude from Lines 10 and 23 sales to non-affiliated UGI members. Such sales, if any, should be shown on Lines 11 and 24. (See list attached)
2/ Includes subsidiary Michigan Gas Storage Co.

[8,014]

Exhibit No. 3

[8,014]

59 e

Exhibit No. 3

[8,015]

Schedule 3

CERTAIN FORM CONTRACT

Requests for Alternative Sources of Supply 1/

Line No.	Description Column 1										
	Natural Gas:										
	Peak Day Volume										
	Annual Volume										
	Annual Cost - Total 2/										
	- Unit										
	Name of Supplier										
	Point of Receipt										
	Point of Origin										
	Coal Gasification:										
	Peak Day Volume										
	Annual Volume										
	Annual Cost - Total 2/										
	- Unit										
	Point of Receipt										
	Imported:										
	Liquid:										
	Peak Day Volume										
	Annual Volume										
	Annual Cost - Total 2/										
	- Unit										
	Point of Receipt										
	Marine:										
	Peak Day Volume										
	Annual Volume										
	Annual Cost - Total 2/										
	- Unit										
	Point of Receipt										
	Alaska:										
	Peak Day Volume										
	Annual Volume										
	Annual Cost - Total 2/										
	- Unit										
	Point of Receipt										

The company has no prospects for any additional supply from any of these categories.

1/ Report for each prospect that is currently being contacted by your Company. Report data according to your best judgment. Report only for the portion of the project that, in your judgment, you might participate in. Include volumes reported on Schedule 2.

2/ Include all costs required to introduce this gas into your transmission or distribution system on a basis equivalent to natural gas with a Btu content of 1,000 Btu per cubic foot @ 14.73 psia.

Exhibit No. 4

[8,016]

[SRI Emblem] STANFORD RESEARCH INSTITUTE
Menlo Park California 94025 • U.S.A.

EXHIBIT No. 4 (SRI-1) April 1970

WITNESS: SHERMAN H. CLARK

UNITED STATES OF AMERICA
FEDERAL POWER COMMISSION

Docket No. AR69-1

IN THE MATTER OF

AREA RATE PROCEEDINGS
(SOUTHERN LOUISIANA)

REQUIREMENTS FOR SOUTHERN LOUISIANA NATURAL GAS THROUGH 1980

SRI Project 8159

Exhibit No. 4

[8,017]

CONTENTS

Part I U.S. DEMAND FOR NATURAL GAS

Part II REQUIREMENTS FOR NATURAL GAS FROM SOUTHERN LOUISIANA

Part III MATERIAL RELATING TO THE EFFECT OF POTENTIAL FUTURE PRICE CHANGE IN THE DEMAND FOR NATURAL GAS

Part IV APPENDIXES

A—ECONOMIC FRAMEWORK

B—COMPETITIVE FUEL PRICES

C—FUELS AND REPORTED END-USE CLASSIFICATIONS INCLUDED IN THIS STUDY, WITH SOURCE NOTES

D—FUEL CONVERSION AND ADJUSTMENT FACTORS

E—U.S. CENSUS REGIONS

Exhibit No. 6

[8,403]

Schedule 2

WEIGHTED AVERAGE INITIAL CONTRACT PRICES
Southern Louisiana: Federal Domain and Onshore
1958-1969

(Cents per Mcf at 15.025 Psia)

Year	Federal Domain	Onshore	
		Excluding Tax Reimbursement	Including Tax Reimbursement
1958	21.6	20.7	22.6
1959	21.4	21.0	23.1
1960	21.2	21.0	22.8
1961	21.4	20.7	22.7
1962	21.4	20.8	21.8
1963	19.5	19.8	19:9
1964	19.0	18.7	18.8
1965	19.2	20.5	20.6
1966	19.3	20.4	20.4
1967	20.2	20.6	20.6
1968	20.7	20.9	20.9
1969	21.1	21.2	21.2

[8,405]

Exhibit No. 6

[8,405]

Schedule 3

NUMBER OF CONTRACTS AND INITIAL ANNUAL VOLUMES
UNDER NEW CONTRACTS
Southern Louisiana
1958-1969

Year of Contract	Number of Contracts			Initial Annual Volumes		
	Federal Domain	Onshore	Total	Federal Domain	Onshore	Total
				(Billions of Cubic Feet at 15.025 psia)		
1958	13	129	142	51.4	201.7	253.1
1959	7	98	105	25.2	134.9	160.1
1960	6	105	111	16.1	168.1	184.2
1961	10	60	70	62.4	56.4	118.8
1962	4	37	41	27.0	50.5	77.5
1963	1	40	41	12.9	219.8	232.7
1964	2	35	37	22.5	59.2	81.6
1965	7	52	59	38.6	132.5	171.1
1966	8	52	60	69.6	125.1	194.7
1967	28	83	111	262.8	154.3	417.1
1968	55	52	107	211.2	86.7	297.8
1969	69	70	139	281.5	103.6	385.0

EXHIBIT NO. 7 (REVISED)
SCHEDULE 1

SHUT-IN GAS COMPLETION DATA AS OF DECEMBER 31, 1969
SOUTHERN LOUISIANA AREA, FEDERAL DOMAIN

Detail of Reasons Reported Gas Completions are Shut-In:	Total Shut-In Gas Completions (a)	Number of Shut-In Gas Completions Committed to Contract (b)	Number of Shut-In Gas Completions Uncommitted (c)
1. Delivery capacity not required in reporting month	42	42	0
2. Insufficient pressure to deliver into sales line	74	74	0
3. Waiting on installation of production and/or pipeline facilities	261	258	3
4. Workover pending	56	56	0
5. Gas cap completion	57	54	3
6. Junked	24	24	0
7. Depleted	151	151	0
8. Too remote and/or reserves insufficient to justify contract or connection	72	25	47
9. Contract negotiations in progress	22	6	16
10. Other	129	129	0
11. Total Reported Shut-In Gas Completions	888	819	69

65 e

[8,418]

Exhibit No. 7

[8,418]

EXHIBIT NO. 7 (REVISED)
SCHEDULE 3

SHUT-IN GAS COMPLETION DATA AS OF DECEMBER 31, 1969
SOUTHERN LOUISIANA AREA, EXCLUDING FEDERAL DOMAIN

Detail of Reasons Reported Gas Completions are Shut-In:	Total Shut-In Gas Completions (a)	Number of Shut-In Gas Completions Committed to Contract (b)	Number of Shut-In Gas Completions Uncommitted (c)
1. Delivery capacity not required in reporting month	81	81	0
2. Insufficient pressure to deliver into sales line	153	153	0
3. Waiting on installation of production and/or pipeline facilities	81	78	3
4. Workover pending	162	161	1
5. Gas cap completion	112	108	4
6. Junked	15	15	0
7. Depleted	776	771	5
8. Too remote and/or reserves insufficient to justify contract or connection	133	110	23
9. Contract negotiations in progress	14	1	13
10. Other	173	163	10
11. Total Reported Shut-In Gas Completions	1,700	1,641	59

[8,420]

Exhibit No. 8

[8,422]

EXHIBIT No. 8 (RLL)

Witness: Russell L. Lindvall

FEDERAL POWER COMMISSION
BUREAU OF NATURAL GAS

RESERVE, PRODUCTION AND DRILLING STATISTICS FOR THE UNITED STATES AND SOUTHERN LOUISIANA

Docket No. AR69-1

AREA RATE PROCEEDING
SOUTHERN LOUISIANA AREA
Washington, D. C.

AMERICAN GAS ASSOCIATION
United States
Natural Gas
Estimated Proved Recoverable Reserves

Pressure Base = 14.73 psia at 60°F or Thousands of Barrels of 42 U.S. Gallons

All Volumes as of December 31st

Schedule No. 1
Sheet 1 of 10

Line No.	Year (A)	Net Production (B)	Reserves Total (C)	Extensions (D)	Revisions (E)	New Field Discoveries (F)	New Reservoir Discoveries (G)	Net Change in Non-Proved Classes (Not Applicable for Liquids) (H)	New Reserves, Recovery (I)	Associated Reserves (J)	Dissolved Reserves (K)	Gas in Underground Storage (Not Applicable for Liquids) (L)	Sale or Loss (M)	Gross Additions (N)
1.	1945		164,884,923											
2.	1946	8,845,778	189,703,813	33,638,868			0		216,809,468	25,968,726	33,977,350	0	12,323,090	12,638,868
3.	1947	9,599,238	165,025,748	7,919,538			5,398,849		219,108,399	27,564,133	38,398,888	0	5,321,952	10,921,187
4.	1948	8,975,028	159,975,085	8,716,166			5,146,148	31,928	220,705,958	27,279,598	38,279,598	886,758	7,849,891	13,971,598
5.	1949	8,813,116	179,101,493	8,017,846			5,597,818	80,897	225,438,880	27,638,826	38,813,398	896,975	6,164,437	13,687,761
6.	1950	8,995,914	183,584,965	9,119,966			5,861,794	85,055	229,818,849	28,029,750	39,395,189	939,836	5,313,052	13,998,796
7.	1951	9,843,473	196,758,868	23,859,938			3,402,898	239,030	233,644,898	28,554,723	39,877,188	971,865	8,126,165	16,097,838
8.	1952	8,596,716	196,621,966	8,885,868			5,381,498	297,779	236,880,828	28,957,923	39,711,397	869,634	5,877,698	15,165,378
9.	1953	9,188,382	204,996,743	13,998,736			7,853,000	812,696	244,680,888	29,818,888	41,268,685	1,283,162	11,447,197	20,955,582
10.	1954	9,995,951	214,951,913	8,807,151			5,379,919	90,118	249,898,739	30,516,908	42,187,895	1,371,674	882,168	9,437,188
11.	1955	10,863,167	223,149,548	15,909,838			5,488,009	87,161	255,819,191	30,161,116	41,931,383	1,363,815	13,921,833	21,961,700
12.	1956	10,818,685	236,183,215	19,218,299			5,606,844	233,658	259,163,776	31,167,753	43,367,021	1,409,096	15,000,671	21,819,195
13.	1957	11,139,899	246,230,137	11,057,936			5,997,119	176,797	267,338,108	32,083,169	44,645,433	1,477,813	8,716,952	20,186,818
14.	1958	11,188,831	258,381,798	13,156,496			5,830,828	87,878	276,896,569	33,156,225	46,108,877	1,530,181	7,531,655	18,958,308
15.	1959	12,373,163	262,276,131	11,952,108			5,760,965	161,180	283,179,939	34,161,186	47,518,977	1,580,871	6,169,639	20,791,798
16.	1960	13,019,198	268,306,268	7,993,088			6,606,163	851,878	286,991,595	35,183,146	48,939,145	1,629,168	3,165,895	18,175,198
17.	1961	13,198,849	268,373,618	20,198,498			6,807,789	259,853	293,688,186	35,913,167	49,948,888	1,658,688	5,867,216	27,325,945
18.	1962	13,838,973	278,278,763 3/	13,188,798			6,899,168	253,198	296,887,338	36,396,888	50,778,579	1,689,888	6,006,163	19,453,118
19.	1963	14,156,885	284,153,833	13,596,333			5,877,898	883,868	302,819,639	37,196,888	51,808,883	1,722,189	5,872,189	19,118,175
20.	1964	15,162,691	283,153,468	13,368,837			6,898,998	295,111	307,388,180	38,018,198	52,884,893	1,758,763	5,389,888	20,117,119

3/ Agrees with conversion from 14.65 to 14.73 psia of data contained in the AGA, 23rd Annual Report, but does not agree with reserve figure given on 14.73 psia on Table VII page 115 of 1963 AGA, 23rd Annual Report.

Exhibit No. 8

[8,431]

[8,468]

Exhibit No. 8

[8,468]

Comparison of Total Drilling, Exploratory and Development Statistics

South Louisiana - Onshore

World Oil Magazine 1/

Line Number	Years (1)	Oil Wells			Gas Wells			Dry Holes			Service Wells			Total Wells		
		No. of Oil Wells (2)	Footage Drilled (3)	Average Depth (4)	No. of Gas Wells (5)	Footage Drilled (6)	Average Depth (7)	No. of Dry Holes (8)	Footage Drilled (9)	Average Depth (10)	No. of Wells (11)	Footage Drilled (12)	Average Depth (13)	Total Wells (14)	Total Footage (15)	Average Depth (16)
1.	1957															
2.	1958															
3.	1959															
4.	1958	605	6,377,973	9,525	667	5,597,606	12,908	697	7,736,574	10,918	3	26,073	8,678	1,632	27,238,826	10,535
5.	1959	745	6,999,532	9,395	723	5,871,010	12,110	753	8,095,185	10,750	3	28,559	9,520	1,824	18,976,906	10,401
6.	1960	779	6,939,734	9,590	895	5,592,159	12,508	669	7,026,323	10,413	0			2,483	17,558,216	10,179
7.	1961	736	6,864,929	9,438	845	5,068,970	12,109	724	7,304,799	10,087	0			2,285	17,238,698	10,888
8.	1962	749	7,095,872	9,487	936	5,960,997	12,547	805	8,058,888	10,163	0			2,790	18,851,757	10,539
9.	1963	758	7,183,615	9,477	981	6,207,800	12,666	795	7,859,658	10,410	3	28,889	9,629	2,537	17,279,732	10,536
10.	1964	681	6,370,535	9,401	811	5,581,669	12,108	701	7,169,559	10,666	1	9,050	9,050	2,194	19,109,814	10,165
11.	1965	701	6,706,852	9,570	748	5,478,497	12,893	713	7,271,794	10,628	4	41,345	10,899	2,436	18,899,138	9,998
12.	1966	681	6,197,545	9,095	579	5,151,530	13,481	668	6,811,705	10,535	5	44,168	11,651	2,506	18,100,795	10,128
13.	1967	526	5,157,826	9,803	369	3,098,895	12,119	529	6,198,907	10,514	8	86,728	13,366	1,816	14,776,560	10,855
14.	1968	504	5,051,909	9,953	188	2,366,126	12,586	480	4,812,688	10,077	3	8,016	8,016	1,363	13,836,859	9,931
15.	1969	363	3,335,359	9,913	809	8,537,390	13,151	444	4,908,838	10,997	7	69,853	9,888	1,883	16,813,838	10,680
16.																
17.																
18.																
19.																
20.																

1/ The World Oil Magazine, Annual Forecast Review Issues (February 15)

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Exhibit No. 8-A

[8,477]

Exhibit No. 8-A

[8,481]

Exhibit No. 9

[8,488]

A number of studies have been made during recent years of natural gas supply-demand relationships—past, present and future—by government and industry sources. Almost invariably these studies utilized understated projections of gas demand or optimistic estimates of future reserve additions, or both. The forecasts from such studies have proven to be inaccurate and misleading.

We have made an intensive study covering a short time span in the interests of accuracy. Our projections and forecasts are focused on the five year period 1969-1973.

In addition to looking at the national picture we have examined the supply-demand relationships for eight supply areas. One of the most important of these areas, South Louisiana, was selected for detailed analysis of the reserve inventory-deliverability relationship, including an estimate of the approximate time (and reserve to production (R/P) ratio level) of deliverability failure. Other major supply areas will be examined on a comparable basis in the future. Potential and supplemental sources of gas have been evaluated and described as to raw material resources and technology and, where applicable, assessments have been made of cost and timing of entry into the energy market.

In addition to using FPC Forms 11 and 15 and other material in FPC files, we have relied upon both published information and informal communications with other government agencies, especially the Office of Coal Research and the Bureau of Mines of the Department of the Interior and the Atomic Energy Commission. Included in this report are materials on the natural gas reserves of

Canada and Mexico and imports and exports of natural gas which in prior years have been issued to the public in the form of separate reports or news releases.

Much of the factual base for this report is industry supplied data, including particularly the American Gas Association (AGA) proven reserve estimates and production information. The gas supply statistics of the American Gas Association are compiled from the confidential records of individual independent producers and pipeline companies. Neither the confidential reserve data of these companies nor the exact method by which this data is summarized for the American Gas Association reports have ever been divulged to the Federal Power Commission. For purposes of this report we have accepted at face value all industry-furnished supply data. Our conclusions must

Exhibit No. 11

Drilling Statistics
Source --- AAPG
Area --- United States
Category --- Total Exploratory Drilling

Schedule No. 3
Sheet 2 of 2

Line No.		Year 1937 (a)	1938 (b)	1939 (c)	1940 (d)	1941 (e)	1942 (f)	1943 (g)	1944 (h)	1945 (i)	1946 (j)	1947 (k)	1948 (l)
1.	Oil Wells												
2.	Number of Wells	1,945	1,745	1,702	1,321	1,157	1,211	1,314	1,219	946	1,030	1,039	863
3.	Footage Drilled (000)	9,794	8,712	8,545	6,829	5,900	6,205	6,409	6,715	5,366	5,860	5,990	5,036
4.	Average Depth	5,036	4,993	5,021	5,170	5,099	5,124	4,877	5,509	5,672	5,708	5,765	5,833
5.	% of Total Wells Excl. Service	13.22	13.22	12.90	11.29	10.53	11.23	12.32	11.34	9.99	9.98	11.46	9.72
6.	Gas & Gas Condensate Wells												
7.	Gas Wells												
8.	Number of Wells	550	568	644	613	624	542	475	392	328	378	394	342
9.	Footage Drilled (000)	2,844	3,024	3,409	3,049	3,285	2,977	2,421	2,238	1,908	2,633	2,429	2,329
10.	Average Depth	5,170	5,323	5,294	4,974	5,264	5,493	5,097	5,759	5,817	6,965	6,164	6,810
11.	% of Total Wells Excl. Service	3.74	4.30	4.88	5.24	5.68	5.02	4.45	3.65	3.47	3.66	4.34	3.85
12.	Gas Condensate Wells												
13.	Number of Wells	315	254	268	255	189	229	189	185	187	200	162	88
14.	Footage Drilled (000)	3,123	2,449	2,622	2,417	1,965	2,210	1,809	1,946	1,849	2,248	1,802	990
15.	Average Depth	9,915	9,640	9,783	9,479	10,395	9,652	9,569	10,516	9,886	11,241	11,123	11,255
16.	% of Total Wells Excl. Service	2.14	1.92	2.03	2.18	1.72	2.12	1.77	1.72	1.98	1.93	1.78	0.99
17.	Total Gas and Gas Condensate												
18.	Number of Wells	865	822	912	868	813	771	664	577	515	578	556	430
19.	Footage Drilled (000)	5,967	5,472	6,031	5,466	5,249	5,187	4,230	4,204	3,757	4,881	4,231	3,320
20.	Average Depth	6,898	6,657	6,613	6,298	6,457	6,728	6,370	7,285	7,295	8,445	7,609	7,720
21.	% of Total Wells Excl. Service	5.88	6.23	6.91	7.42	7.40	7.14	6.23	5.37	5.44	5.60	6.13	4.84
22.	Dry Holes												
23.	Number of Wells	11,904	10,632	10,577	9,515	9,022	8,815	8,686	8,951	8,005	8,705	7,464	7,586
24.	Footage Drilled (000)	53,420	47,300	48,676	43,535	43,293	42,223	42,847	44,578	40,081	44,462	38,903	42,603
25.	Average Depth	4,488	4,449	4,602	4,575	4,799	4,793	4,932	4,980	5,007	5,108	5,212	5,615
26.	% of Total Wells Excl. Service	80.90	80.55	80.18	81.30	82.03	81.64	81.43	83.29	84.57	84.40	82.39	85.45
27.	Total Wells Drilled for Hydrocarbons												
28.	Number of Wells	14,714	13,199	13,191	11,704	10,992	10,797	10,664	10,747	9,466	10,313	9,059	8,879
29.	Footage Drilled (000)	69,181	61,484	63,253	55,831	54,442	53,616	53,485	55,497	49,204	55,223	49,124	50,958
30.	Average Depth	4,702	4,658	4,795	4,770	4,953	4,966	5,015	5,164	5,197	5,353	5,422	5,739

[8,615]

[8,630]

Exhibit No. 11

[8,630]

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Drilling Statistics
Source --- World Oil
Area --- South Louisiana
Category --- Total Drilling-Exploratory and Development

Schedule No. 6
Sheet 2 of 2

Line No.		Year											
		1957 (a)	1958 (b)	1959 (c)	1960 (d)	1961 (e)	1962 (f)	1963 (g)	1964 (h)	1965 (i)	1966 (j)	1967 (k)	1968 (l)
1.	Oil Wells												
2.	Number of Wells	1,056	976	1,033	1,000	1,013	1,067	1,083	1,074	1,150	1,076	909	929
3.	Footage Drilled (000)	10,627	9,246	9,768	9,498	9,710	10,482	10,514	10,120	10,441	10,212	8,676	8,446
4.	Average Depth	10,064	9,473	9,456	9,498	9,585	9,823	9,709	9,423	9,079	9,490	9,544	9,091
5.	% of Total Wells Excl. Service	45.15	46.12	45.21	45.70	46.47	42.43	44.77	43.84	43.45	42.94	39.96	39.20
6.	Gas and Gas Condensate Wells												
7.	Gas Wells												
8.	Number of Wells	159	109	128	138	NA	NA	NA	NA	NA	NA	NA	NA
9.	Footage Drilled (000)	1,812	1,272	1,515	1,604								
10.	Average Depth	11,398	11,667	11,836	11,621								
11.	% of Total Wells Excl. Service	6.80	5.13	5.60	6.31								
12.	Gas Condensate Wells												
13.	Number of Wells	223	216	246	221	NA	NA	NA	NA	NA	NA	NA	NA
14.	Footage Drilled (000)	2,721	2,632	3,059	2,783								
15.	Average Depth	12,200	12,187	12,435	12,593								
16.	% of Total Wells Excl. Service	9.53	10.21	10.77	10.10								
17.	Total Gas and Gas Condensate												
18.	Number of Wells	382	325	374	359	314	338	270	294	249	238	259	298
19.	Footage Drilled (000)	4,533	3,904	4,574	4,387	3,854	4,015	3,393	3,554	3,172	3,017	3,140	3,582
20.	Average Depth	11,866	12,013	12,230	12,219	12,273	12,166	12,565	12,089	12,738	12,676	12,123	12,018
21.	% of Total Wells Excl. Service	16.33	15.36	16.37	16.41	14.40	13.12	11.16	12.00	9.84	9.50	11.39	12.57
22.	Dry Holes												
23.	Number of Wells	901	815	878	829	853	1,118	1,066	1,082	1,131	1,192	1,107	1,143
24.	Footage Drilled (000)	9,352	8,719	9,473	8,756	8,912	11,904	11,189	11,557	11,974	12,329	11,607	12,081
25.	Average Depth	10,379	10,698	10,790	10,563	10,448	10,647	10,496	10,681	10,587	10,511	10,485	10,569
26.	% of Total Wells Excl. Service	38.52	38.46	38.42	37.89	39.13	44.43	44.07	44.16	44.70	47.56	48.66	48.23
27.	Total Wells Drilled for Hydrocarbons												
28.	Number of Wells	2,339	2,116	2,285	2,188	2,180	2,515	2,419	2,450	2,530	2,506	2,275	2,370
29.	Footage Drilled (000)	24,512	21,869	23,815	22,641	22,475	26,400	25,096	25,231	25,587	25,758	23,423	24,108
30.	Average Depth	10,480	10,320	10,422	10,348	10,310	10,497	10,375	10,298	10,113	10,279	10,296	10,172
31.	Service Wells												
32.	Number of Wells	0	3	3	0	1	0	3	4	11	9	11	12
33.	Footage Drilled (000)	0	26	29	0	6	0	22	34	114	84	113	112
34.	Average Depth	0	8,667	9,667	0	6,170	0	7,183	8,388	10,341	9,321	10,230	9,349
35.	Total All Wells												
36.	Number of Wells	2,339	2,119	2,288	2,188	2,181	2,515	2,422	2,454	2,541	2,515	2,286	2,382
37.	Footage Drilled (000)	24,512	21,895	23,844	22,641	22,482	26,400	25,118	25,264	25,700	25,842	23,535	24,221
38.	Average Depth	10,480	10,333	10,421	10,348	10,308	10,497	10,371	10,295	10,114	10,275	10,295	10,168

Drilling Statistics
Source --- AAPG
Area --- South Louisiana
Category --- Total Exploratory Drilling

Schedule No. 6
Sheet 2 of 2

Line No.		Year											
		1937 (a)	1938 (b)	1939 (c)	1940 (d)	1941 (e)	1942 (f)	1943 (g)	1944 (h)	1945 (i)	1946 (j)	1947 (k)	1948 (l)
1.	Oil Wells												
2.	Number of Wells	116	103	112	69	45	40	35	68	55	76	84	66
3.	Footage Drilled (000)	1,308	1,074	1,177	749	520	434	366	734	594	846	1,012	842
4.	Average Depth	11,277	10,429	10,509	11,144	11,550	10,842	10,661	11,007	11,349	11,634	12,049	12,730
5.	% of Total Wells Excl. Service	13.93	14.37	14.23	11.75	7.44	6.66	7.32	8.80	8.13	8.79	11.23	8.29
6.	Gas and Gas Condensate Wells												
7.	Gas Wells												
8.	Number of Wells	33	28	18	13	13	6	3	19	14	25	26	45
9.	Footage Drilled (000)	380	268	213	149	129	70	35	220	177	441	296	615
10.	Average Depth	11,528	9,526	11,855	11,492	9,937	11,615	10,988	11,573	11,053	12,602	12,351	13,672
11.	% of Total Wells Excl. Service	3.96	3.63	2.29	2.21	2.15	1.00	0.67	2.44	2.37	4.05	3.21	5.65
12.	Gas Condensate Wells												
13.	Number of Wells	134	104	114	78	64	57	39	64	54	74	57	37
14.	Footage Drilled (000)	1,537	1,250	1,373	969	807	722	761	858	723	1,015	804	519
15.	Average Depth	12,395	12,027	12,046	12,434	12,613	12,660	12,906	13,405	13,388	13,984	14,107	14,024
16.	% of Total Wells Excl. Service	14.87	14.50	14.49	13.29	10.59	9.48	7.86	8.28	8.00	8.56	7.62	4.65
17.	Total Gas and Gas Condensate												
18.	Number of Wells	157	130	132	91	77	63	64	83	70	109	81	82
19.	Footage Drilled (000)	1,917	1,498	1,587	1,118	937	791	816	1,078	900	1,476	1,101	1,134
20.	Average Depth	12,212	11,526	12,020	12,291	12,164	12,560	12,756	12,986	12,855	13,543	13,586	13,831
21.	% of Total Wells Excl. Service	18.85	18.13	16.78	15.50	12.74	10.48	8.53	10.74	10.37	12.61	10.83	10.30
22.	Dry Holes												
23.	Number of Wells	560	484	543	427	483	498	632	622	550	680	583	648
24.	Footage Drilled (000)	6,259	5,476	6,095	4,931	5,544	5,512	7,045	6,841	5,814	7,848	6,517	7,472
25.	Average Depth	11,176	11,315	11,224	11,548	11,480	11,068	11,148	10,999	10,571	11,542	11,179	11,531
26.	% of Total Wells Excl. Service	67.23	67.50	69.00	72.74	79.83	82.86	84.16	80.47	81.48	78.61	77.94	81.41
27.	Total Wells Drilled for Hydrocarbons												
28.	Number of Wells	833	717	787	587	605	601	731	773	675	865	748	796
29.	Footage Drilled (000)	9,484	8,049	8,859	6,819	7,001	6,737	8,448	8,673	7,338	10,210	8,630	9,448
30.	Average Depth	11,386	11,226	11,257	11,616	11,572	11,209	11,349	11,220	10,872	11,803	11,537	11,867

[8,697]

Exhibit No. 11

[8,697]

97

CHART 27

EXPLORATION AND DEVELOPMENT EXPENDITURES
UNITED STATES

E & D Expenditures (Billion Dollars)

YEAR

Chase Bank Total

JAS Total

Chase Bank Group

All Others - Chase

Estimated Drilling Expenditures
(Costs Through Christmas Tree)
Source -- IAR

Schedule No. 29
Sheet 2 of 2

Line No.	Year (a)	Well Types (b)	United States Number of Wells (c)	United States Expenditure Total $ (d)	United States Expenditure Per Well $ (e)	South Louisiana - Onshore 1/ Number of Wells (f)	South Louisiana - Onshore 1/ Expenditure Total $ (g)	South Louisiana - Onshore 1/ Expenditure Per Well $ (h)	South Louisiana - Offshore Number of Wells (i)	South Louisiana - Offshore Expenditure Total $ (j)	South Louisiana - Offshore Expenditure Per Well $ (k)	South Louisiana Number of Wells (l)	South Louisiana Expenditure Total $ (m)	South Louisiana Expenditure Per Well $ (n)
1.	1963	Oil	20,678	1,071,138,207	51,801	751	120,754,233	160,791	338	120,466,120	356,409	1,089	241,220,353	221,506
2.		Gas	4,779	441,425,691	92,368	206	66,048,293	320,623	83	44,725,716	538,864	289	110,774,009	383,301
3.		Dry	16,396	790,300,052	48,201	772	116,475,924	150,876	309	105,210,236	340,486	1,081	221,686,160	205,075
4.		Total	41,853	2,302,863,950	55,023	1,729	303,278,450	175,402	730	270,402,072	370,414	2,459	573,680,522	233,298
5.	1964	Oil	21,012	1,062,994,900	50,589	663	108,389,270	163,483	429	155,281,680	361,961	1,092	263,670,750	241,457
6.		Gas	4,874	510,564,089	104,752	231	80,680,578	349,267	108	54,592,280	505,484	339	135,272,858	399,035
7.		Dry	17,600	853,808,197	48,512	682	119,663,830	175,460	364	120,595,802	331,307	1,046	240,259,632	229,694
8.		Total	43,486	2,427,367,186	55,820	1,576	308,733,678	195,897	901	330,469,562	366,781	2,477	639,203,240	258,055
9.	1965	Oil	18,857	1,066,795,319	56,573	753	117,478,383	156,014	468	190,549,888	407,158	1,221	308,028,271	252,275
10.		Gas	4,772	486,099,969	101,865	187	67,900,224	363,103	90	58,956,849	632,854	277	126,857,073	450,748
11.		Dry	15,967	848,541,238	53,143	674	120,252,260	178,416	380	139,015,413	365,830	1,054	259,267,673	345,985
12.		Total	39,596	2,401,436,526	60,648	1,614	305,630,867	189,362	938	386,522,150	412,071	2,552	692,153,017	271,220
13.	1966	Oil	15,856	985,753,591	62,169	640	102,691,021	160,455	456	201,561,259	442,020	1,096	304,252,280	277,602
14.		Gas	4,060	543,251,563	133,806	198	88,511,692	447,029	138	92,159,433	667,822	336	180,671,125	537,712
15.		Dry	14,605	831,735,157	56,949	678	126,696,690	183,918	358	144,733,953	404,285	1,036	269,430,645	260,068
16.		Total	34,521	2,360,740,311	68,386	1,516	315,899,403	208,377	952	438,454,647	460,562	2,468	754,354,050	305,654
17.	1967	Oil	14,935	995,368,948	66,647	483	88,127,831	182,459	425	188,031,968	442,428	908	276,159,799	304,141
18.		Gas	3,558	501,660,931	140,995	186	79,599,978	427,957	131	85,134,706	649,883	317	164,734,684	519,668
19.		Dry	13,045	802,148,507	61,491	614	121,796,078	198,365	358	139,275,072	389,037	972	261,071,150	268,592
20.		Total	31,538	2,299,178,386	72,902	1,283	289,523,887	225,662	914	412,441,746	451,249	2,197	701,965,633	319,511
21.	1968	Oil	13,767	1,089,328,359	79,126	530	95,957,562	181,052	441	211,997,328	480,720	971	307,954,890	317,152
22.		Gas	3,324	493,736,115	148,537	188	83,507,173	444,187	163	95,624,317	586,652	351	179,131,490	510,346
23.		Dry	12,485	826,295,925	66,183	618	126,442,893	204,600	316	116,665,902	369,196	934	243,108,795	260,288
24.		Total	29,576	2,409,360,399	81,463	1,336	305,907,628	228,973	920	424,287,547	461,182	2,256	730,195,175	323,668

1/ Oil and Gas wells were not segregated for this year. The Expenditure and Number of Wells shown includes both well types.

2/ South Louisiana - Onshore determined by difference between Total South Louisiana and South Louisiana - Offshore.

79 e

Exhibit No. 11

[8,711]

[8,711]

Exhibit No. 11

[8,712]

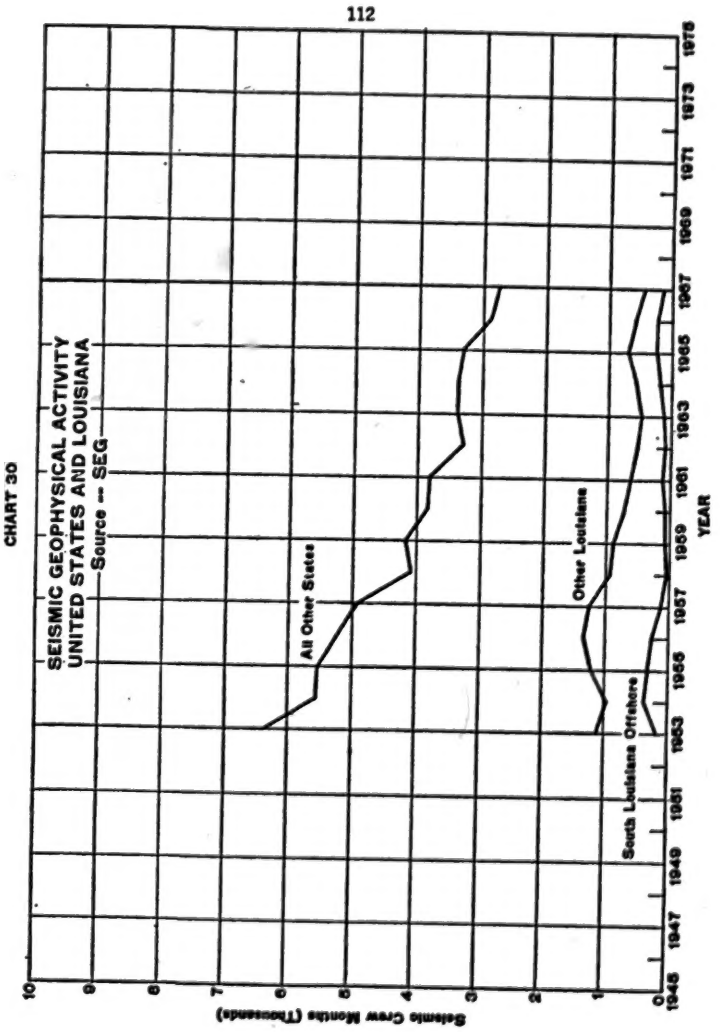


Exhibit No. 11

[8,714]

114

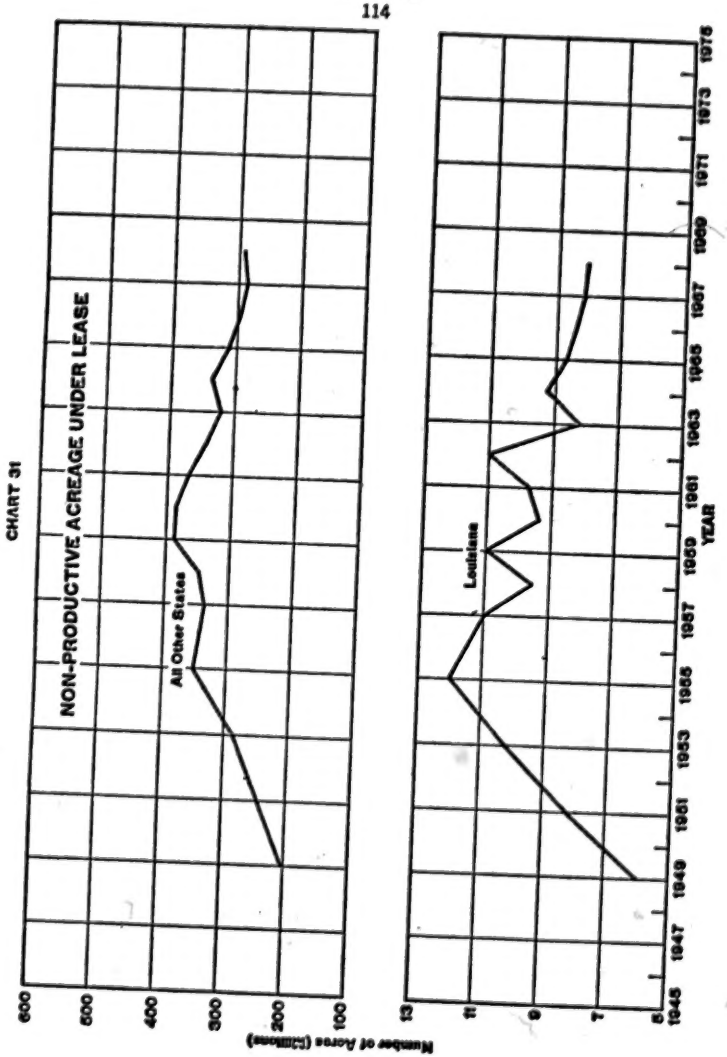


Exhibit No. 19

[8,799]

Docket No. AR69-1
Phase I
Hearing Exhibit 19
Witness: John C. Jacobs, Jr.

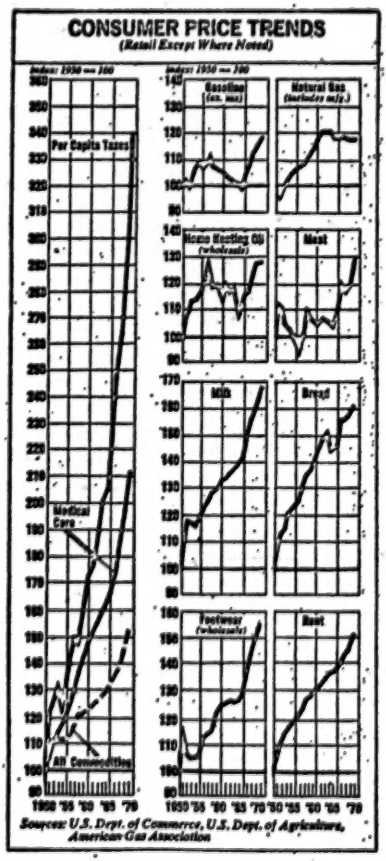
SUBCOMMITTEE PERSONNEL
OF THE
COMMITTEE ON NATURAL GAS RESERVES
AMERICAN GAS ASSOCIATION

ADAMS, W. (W. Tex.)
ALBERS, D.C. (Rocky)
ANDERSON, D.C. (Mid-C.)
ANDREA, D.W. (Rocky)
BABIONE, H.A. (Pac.)
BARRETT, R.J. (SE)
BECKNER, N.H. (Rocky)
BENAVIDES, T. (Mid-C.)
BERQUIST, J.F. (Pac.)
BOLCH, W.H. (W.Tex.)
BOOMER, J.R. (App.)
BORGAN, R.L. (W.Tex.)
BOYER, A.J. (Rocky)
BROWN, J.R. (Rocky)
BUCK, J.R. (Mid-C.)
CAMPBELL, A.E. (Mid-C.)
CASEY, R. (W.Tex.)
CHATFIELD, L.E. (Pac.)
CLARK, J.D. (S.La.)
CLARK, S.E. (Mid-C.)
COLE, P.A. (Mid-C.)
COX, J.J. (S.La.)
CROUSHORN, A.L. (Pac.)
DAVIS, C.A. (Pac.)
DAVIS, G.W. (Rocky)
DEVEREAD, P. (Mid-C.)
ELENBAAS, J. (Mid-C.)
EWING, H.H. (Pac.)
FARRIS, R.G. (Mid-C.)
FORE, Jr., S.D. (Rocky)
(Mid-C.)
FREELAND, J. (Tex.G.C.)
GALLAGHER, R.W. (S.Cen.)
GARCIA, R.T. (NE Tex.)
GARLAND, A.M. (Pac.)
GARNER, E.S. (Pac.)
GIBBS, R.B. (S.La.)
GIBBS, D.E. (Mid-C.)
GLOVER, H.A. (Mid-C.)
GORMAN, R.W. (Mid-C.)
GUILBEAUD, A. (S.La.)
GYNN, T.A. (Rocky)
HAAVIK, E.A. (Pac.)
HALSELL, H. (S.Cen.)
HARDMAN, C.W. (Mid-C.)
HAUBER, F.C. (App.)
HERREL, S.F. (Mid-C.)
HOLDEMAN, J. (Mid-C.)
HORN, C.R. (Mid-C.)
HOWELL, R. (Mid-C.)
HOWES, W.A. (NE Tex.)
(Mid-C.)
HOWARD, R.E. (W.Tex.)
HUDGINS, M.R. (W.Tex.)
HUGHES, Jr., C.F. (Mid-C.)
HUTTON, D.A. (Rocky)
(Mid-C.)
JOHNSON, A. (App.)
JORDAN, J.R. (NE Tex.)
KALIL, W. (NE Tex.)
KAUFAMAN, H.D. (W.Tex.)
(Mid-C.)
KERR, J. (S.La.)
KIRBY, R.L. (Rocky)
LANE, R.D. (W.Tex.)
LEBLANC, C.J. (S.La.)
LEWIS, F.W. (App.)
LINGER, S.M. (App.)
LLOYD, F.T. (Pac.)
LUDWICK, L.E. (Rocky)
LYNCH, H. (Mid-C.)
LYONS, D. (Mid-C.)
MARTIN, M.G. (S.Cen.)
McKENZIE, R.E. (S.La.)
McMICHAEL, C.R. (S.Cen.)
McUSIC, J.M. (Mid-C.)
MEAKER, H.N. (S.La.)
MEURY, R.A. (App.)
MICIOTTO, J.A. (SE)
MORRISON, W.F. (NE Tex.)
MINCHY, F.A. (S.Cen.)
MYERS, R.G. (Rocky)
NAERT, G.A. (W.Tex.)
NUTTER, D.C. (Pac.)
PEDIGO, H.E. (Mid-C.)
PLANK, R.F. (S.La.) (SE)
(S.Cen.)
PRITCHETT, R. (W.Tex.)
REED, L.N. (Mid-C.)
RHODES, R.B. (Rocky)
RIETMAN, N.D. (Mid-C.)
RILEY, H.G. (Mid-C.)
RIST, B.C. (Mid-C.)
SADIGHI, S. (Rocky)
SATERFIEL, C. (SE)
SCHERER, D.R. (SE)
SMITHERMAN, M.E. (NE Tex.)
SNELL, J.A. (Rocky)
STEELE, H.C. (Tex. G.C.)
STONE, V. (W.Tex.)
STOUT, C.E. (App.)
STUART, O.M. (Tex. G.C.)
SWINGLE, M.P. (S.La.) (SE)
THIEMES, W.A. (W.Tex.)
UZZELL, W. (W.Tex.)
VARY, J.A. (Mid-C.)
VOSS, W.R. (S.La.) (SE)
WHITAKER, M.T. (Pac.)
WIEDER, A.H. (Rocky)
WILLIAMS, R.G. (Tex. G.C.)
WITHROW, E.J. (Mid-C.)
WORRELL, J.M. (Rocky)
YOUNG, T.B. (NE Tex.)

Exhibit No. 20

[8,800]

Docket No. AR69-1
Phase 1
Hearing Exhibit 20
Witness: John G. Winger



THE CHASE MANHATTAN BANK, N.A.

Exhibit No. 21

[8,801]

EXHIBIT NO. 21 (RLS-1)

Witness: Radford L. Schantz

UNITED STATES OF AMERICA
FEDERAL POWER COMMISSION

Docket No. AR69-1

IN THE MATTER OF
AREA RATE PROCEEDING
(SOUTHERN LOUISIANA AREA)

ECONOMIC EVIDENCE PERTAINING TO THE SUPPLY OF AND DEMAND FOR NATURAL GAS IN THE UNITED STATES WITH SPECIAL REFERENCE TO THE SOUTHERN LOUISIANA PRODUCING AREA

Foster Associates, Inc.
Washington, D. C.

May 1, 1970

Exhibit No. 21

[8,809]

Schedule 5

RESERVES ADDITIONS, NET PRODUCTION AND TOTAL PROVED RESERVES
OF NATURAL GAS IN THE UNITED STATES[a]
1947-1969
(Volumes in Billions of Cubic Feet at 14.73 psia)

Year	Reserves Additions (1)	Net Production (2)	Finding-Production Ratio Annual (3)	Finding-Production Ratio Three-Year Moving Average[b] (4)	Total Reserves, End of Year[c] (5)	Reserves-Production Ratio (6)
1947	10,921	5,599	1.95		165,026	29.5
1948	13,823	5,975	2.31	2.10	172,925	28.9
1949	12,606	6,211	2.03	2.02	179,402	28.9
1950	11,985	6,855	1.75	1.93	184,585	26.9
1951	15,966	7,924	2.01	1.81	192,759	24.3
1952	14,268	8,593	1.66	1.97	198,632	23.1
1953	20,342	9,188	2.21	1.63	210,299	22.9
1954	9,547	9,375	1.02	1.81	210,561	22.5
1955	21,898	10,063	2.18	1.85	222,483	22.1
1956	24,716	10,849	2.28	2.06	236,483	21.8
1957	20,008	11,440	1.75	1.89	245,230	21.4
1958	18,897	11,425	1.65	1.69	252,762	22.1
1959	20,621	12,373	1.67	1.45	261,113	21.1
1960	13,844	13,019	1.06	1.31	262,219	20.1
1961	16,350	13,377	1.22	1.22	265,552	19.8
1962	18,768	13,634	1.38	1.28	270,645	19.9
1963	18,104	14,541	1.25	1.31	274,461	18.9
1964	20,105	15,341	1.31	1.29	279,420	18.2
1965	21,158	16,245	1.30	1.23	284,484	17.5
1966	19,246	17,478	1.10	1.18	286,386	16.4
1967	21,093	18,358	1.15	0.95	289,272	15.8
1968	12,038	19,332	0.62	0.71	282,098	14.6
1969	8,338	20,636	0.40		269,907	13.1

a/ Excludes Alaska where reported separately.

b/ Based on three-year moving averages of the data in Cols. (1) and (2) centered on the middle year.

c/ Includes reserves held in underground storage which amounted to 3,602 billion cubic feet at the end of 1969, a net increase of 107 billion cubic feet over 1968.

Source: Reports by the American Gas Association Committee on Natural Gas Reserves.

PA-11571

TRENDS IN NON-ASSOCIATED GAS SUPPLIES COMPARED
WITH ASSOCIATED-DISSOLVED GAS SUPPLIES

CONTINENTAL UNITED STATES

1966 - 1969

	Reserves Additions: Extensions & Revisions (1)	Reserves Additions: New Discoveries (2)	Reserves Additions: Total (3)	Net Production (4)	Finding-to-Production Ratio (5)	Reserves, End of Year a/ (6)	Reserves-to-Production Ratio (7)
	(Volumes in Billions of Cubic Feet at 14.73 Psia)						
NON-ASSOCIATED GAS SUPPLIES							
1966	10,547	5,589	16,136	12,891	1.25	214,682	16.7
1967	12,338	4,946	17,284	13,598	1.27	218,368	16.1
1968	9,900	2,434	12,334	14,691	0.84	216,011	14.7
1969	N.A.	N.A.	N.A.	N.A.	N.A.	206,991	N.A.
ASSOCIATED-DISSOLVED GAS SUPPLIES							
1966	2,682	428	3,110	4,587	0.68	68,479	14.9
1967	3,390	419	3,809	4,760	0.80	67,528	14.2
1968	(642)	346	(296)	4,641	--	62,592	13.5
1969	N.A.	N.A.	N.A.	N.A.	N.A.	59,314	N.A.
TOTAL GAS SUPPLIES							
1966	13,229	6,017	19,246	17,478	1.10	283,161	16.2
1967	15,728	5,365	21,093	18,358	1.15	285,896	15.6
1968	9,258	2,780	12,038	19,332	0.62	278,603	14.4
1969	4,525	3,813	8,338	20,636	0.40	266,305	12.9

a/ Excluding reserves held in underground storage.

Source: Reports by the American Gas Association Committee on Natural Gas Reserves.

N.A. - Not available.

Exhibit No. 21

[8,812]

Schedule 8
Page 1 of 2

CONTINENTAL UNITED STATES

NUMBER OF WELLS DRILLED BY TYPE OF WELL

1960-1969

Year	Productive Wells				Dry Holes		Total Wells	
	Oil Wells		Gas Wells					
	Wildcat	Total	Wildcat	Total	Wildcat	Total	Wildcat	Total
				WORLD OIL				
1960	563	22,245	321	5,146	8,214	18,205	9,098	45,596
1961	517	21,610	290	5,482	7,523	17,313	8,330	44,205
1962	484	21,719	260	5,349	7,102	17,053	7,846	44,121
1963	497	20,129	238	4,565	7,035	16,748	7,770	41,442
1964	532	19,903	241	4,691	7,383	17,678	8,156	42,272
1965	422	18,055	200	4,472	6,870	16,220	7,492	38,747
1966	430	16,201	250	4,317	6,297	15,162	6,977	35,680
1967	420	15,040	172	3,598	5,405	12,922	5,997	31,560
1968	386	13,908	141	3,321	6,079	12,932	6,606	30,161
1969	443	13,153	228	3,637	6,406	13,049	7,077	29,839
				AMERICAN ASSOCIATION OF PETROLEUM GEOLOGISTS				
	Oil Wells		Gas Wells		Dry Holes		Total Wells	
	Exploratory	Total	Exploratory	Total	Exploratory	Total	Exploratory	Total
1960	1,320		866		9,509		11,695	
1961	1,155		808		8,996		10,959	
1962	1,211	NOT	769	NOT	8,793	NOT	10,773	NOT
1963	1,312	REPORTED	663	REPORTED	8,673	REPORTED	10,648	REPORTED
1964	1,215		575		8,937		10,727	
1965	938		513		7,993		9,444	
1966	1,025	16,432	574	4,162	8,676	15,740	10,275	36,334
1967	1,039	15,167	553	3,553	7,433	13,503	9,025	32,223
1968	860	14,150	429	3,378	7,572	12,967	8,861	30,495
1969	1,084	14,330	616	4,072	7,989	13,722	9,689	32,124

Source: World Oil, Forecast Review Issues and American Association of Petroleum Geologists, June Bulletins through 1969 and preliminary report for 1969.

FA-11644

A PROJECTION OF THE CONSUMER DEMAND FOR NATURAL GAS BY GEOGRAPHIC REGION IN THE CONTINENTAL UNITED STATES

1975 and 1980 Projections Compared with 1968

	Billion Cubic Feet a/			Percent of Total			Projected Annual Growth Rates		
	1968 (1)	1975 (2)	1980 (3)	1968 (4)	1975 (5)	1980 (6)	1968 to 1975 (7)	1968 to 1980 (8)	1975 to 1980 (9)
New England	223	346	430	1.2%	1.3%	1.4%	6.5%	5.6%	4.4%
Appalachian	3,565	4,860	5,697	19.1	18.3	18.2	4.5	4.0	3.2
Southeast	1,410	2,198	2,684	7.6	8.3	8.6	6.5	5.5	4.1
Great Lakes	2,445	3,818	4,633	13.1	14.4	14.8	6.6	5.5	3.9
Northern Plains	880	1,102	1,222	4.7	4.2	3.9	3.3	2.8	2.1
Mid-Continent	1,459	1,870	2,163	7.8	7.0	6.9	3.6	3.3	3.0
Gulf Coast	5,363	7,889	9,316	28.7	29.7	29.8	5.7	4.7	3.4
Rocky Mountain	482	601	699	2.6	2.3	2.2	3.2	3.1	3.1
Pacific Southwest	2,581	3,395	3,873	13.8	12.8	12.4	4.0	3.4	2.7
Pacific Northwest	270	451	558	1.4	1.7	1.8	7.6	6.2	4.3
Total, excluding field use b/	18,678	26,530	31,275	100.0	100.0	100.0	5.1	4.4	3.3

a/ Gas at 14.73 psia and 1000 Btu per cubic foot.

b/ Field use includes fuels used on leases for pumping, drilling and other field facilities; fuel and losses and shrinkage at gas processing plants, excluding main line plants; and quantities vented and flared on producing properties.

Source: Future Natural Requirements of the United States, Volume 3, September 1969 as prepared by the Future Requirements Committee.

Schedule 11
Page 1 of 2

Exhibit No. 21

[8,817]

Schedule 11
Page 2 of 2

IDENTIFICATION OF STATES
INCLUDED IN GEOGRAPHIC REGIONS

Region	States
New England	Maine, Vermont, Massachusetts, New Hampshire, Connecticut, Rhode Island
Appalachian	New York, Ohio, Pennsylvania, New Jersey, Delaware, Maryland, Kentucky, West Virginia, District of Columbia, Virginia
Southeast	Tennessee, North Carolina, South Carolina, Georgia, Alabama, Florida
Great Lakes	Michigan, Wisconsin, Illinois, Indiana
Northern Plains	North Dakota, South Dakota, Minnesota, Iowa, Nebraska
Mid-Continent	Kansas, Missouri, Oklahoma
Gulf Coast	Texas, Arkansas, Mississippi, Louisiana
Rocky Mountain	Montana, Wyoming, Utah, Colorado
Pacific Southwest	California, Nevada, Arizona, New Mexico
Pacific Northwest	Washington, Oregon, Idaho

FA-11385

ESTIMATED COST OF PROSPECTIVE IMPORTS OF WESTERN CANADIAN GAS

(¢/Mcf)

Company	1968	1969	1970	1971	1972	1973	Delivery Point	Source
Pacific Gas Transmission								
Average	28.19	28.24	28.69	28.85	28.69	29.01	California-Oregon Border	PGT-Application CP69-346
Incremental				30.38	29.56	29.66		
El Paso Natural Gas								
Average	23.65	23.04					Sumas, Washington	FPC Staff Report on National Gas Supply and Demand; El Paso Application CP69-345; El Paso Application CP70-137 CP70-69 et al., Exhibit 96
Incremental			31.5	31.5				
Rates under new contract at 95% load factor					29.32	30.45		
Midwestern Gas Transmission								
Average	27.32	27.32					International Boundary (Emerson, Manitoba)	Examiner's decision dated 2/18/70 in re Great Lakes Gas Transmission CP70-19 et al., CP70-69 et al., Exh. 96
Incremental (rates at 100% load factor)			32.0¢/	32.0¢/	32.0¢/	32.0¢/		
Michigan Wisconsin Pipe Line								
Rate at International Border (100% load factor)			32.0¢/	32.0¢/	32.0¢/	32.0¢/	Marshfield, Wisconsin	Examiner's decision dated 2/18/70 in re Great Lakes Gas Transmission, CP70-19 et al.
Transportation by Midwestern (100% load factor)			9.32	9.32	9.32	9.32		
			41.32	41.32	41.32	41.32		
Great Lakes Gas Transmission								
Rate under 1966 contract (100% load factor)			28.65	28.65	28.65	28.65	International Boundary (Emerson, Manitoba)	Examiner's decision dated 2/18/70 in re Great Lakes Gas Transmission, CP70-19 et al.
Rate under 1969 contract (100% load factor)			32.0¢/	32.0¢/	32.0¢/	32.0¢/		
Natural Gas Pipeline								
Rate paid to Great Lakes at Crystal Falls, Michigan (100% load factor)			40.03	40.03	40.03	40.03	Joliet and Woodstock, Illinois	Great Lakes Application, CP70-19
Rate paid to Mich-Wis for transportation-exchange service			3.97	3.97	3.97	3.97		
			43.00	43.00	43.00	43.00		
Northern Natural Gas Co.				47.10	40.91b/	40.70b/	North Branch, Minn.	Northern Natural, CP70-40 et al., Exhibit 22

a/ Reduction in rate to 30.0¢ recommended by Examiner Levy in initial decision dated 2/18/70 in re Great Lakes Gas Transmission et al. CP70-19 et al.

b/ Based on deliveries in excess of volumes authorized to be removed from Province of Alberta.

Exhibit No. 21

REGIONAL DISTRIBUTION OF NATURAL GAS IN CONTINENTAL UNITED STATES, 1960

Producing Areas (1)	New England (2)	Appalachian (3)	Southeast (4)	Great Lakes (5)	Northern Plains (6)	Mid-Continent (7)	Gulf Coast (8)	Rocky Mountain (9)	Pacific Southwest (10)	Pacific Northwest (11)	Total (Including Exports) (12)
Percentage Distribution of Net Production to Consuming Regions											
South Louisiana	2.4%	25.8%	16.6%	14.4%	--	1.7%	28.9%	--	--	--	100.0%
Texas Gulf Coast	1.4	14.4	5.2	13.3	--	0.6	63.1	--	--	--	100.0
Hugoton-Anadarko	--	3.7	--	27.4	17.6%	33.2	12.1	4.8%	1.2%	--	100.0
Permian Basin	--	--	--	4.0	13.1	--	26.5	--	56.4	--	100.0
Other Southwest (Distr. 1 & 7E)	1.1	10.0	7.7	4.8	0.7	19.3	36.4	--	--	--	100.0
San Juan Basin	--	--	--	--	--	--	--	1.0	92.3	6.7%	100.0
Rocky Mountain	--	--	--	--	19.9	--	--	76.8	--	3.3	100.0
California	--	--	--	--	--	--	--	--	100.0	--	100.0
All Other	--	99.9	--	0.1	--	--	--	--	--	--	100.0
Continental United States	1.1	18.4	7.1	12.6	4.7	8.1	32.5	2.9	12.3	0.3	100.0
Imports	0.1	0.8	--	16.9	1.7	--	7.2	3.2	36.3	31.1	100.0
Total, including imported gas	1.1	17.8	6.9	12.6	4.6	7.8	31.6	3.0	13.3	1.3	100.0
Source of Natural Gas for Consuming Regions											
South Louisiana	65.0%	60.5%	72.9%	34.5%	--	7.1%	27.4%	--	--	--	30.0%
Texas Gulf Coast	23.2	17.0	13.9	19.5	--	1.5	30.7	--	--	--	18.4
Hugoton-Anadarko	--	3.1	--	32.1	56.3	62.4	5.7	23.7%	1.2%	--	14.7
Permian Basin	--	--	--	3.2	28.9	--	8.5	--	43.0	--	10.2
Other Southwest	11.4	6.6	13.2	4.5	--	29.0	21.0	--	--	--	11.8
San Juan Basin	--	--	--	--	1.9	--	--	1.0	20.9	15.7%	3.0
Rocky Mountain	--	--	--	--	11.7	--	--	69.1	--	6.9	2.7
California	--	--	--	--	--	--	--	--	25.6	--	3.4
All Other	--	12.7	--	1.8	--	--	--	--	--	--	2.3
Continental United States	99.6	99.9	100.0	95.6	98.8	100.0	99.3	93.8	91.0	22.2	96.7
Imports	0.4	0.1	--	4.4	1.2	--	0.7	6.2	9.0	77.8	3.3
Total, including imported gas	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0

Source: Schedule 30.

Schedule 21

[8,839]

Exhibit No. 21

[8,899]

REGIONAL DISTRIBUTION OF NATURAL GAS IN CONTINENTAL UNITED STATES, 1964

Producing Areas	New England	Appalachian	Southeast	Great Lakes	Northern Plains	Mid-Continent	Gulf Coast	Rocky Mountain	Pacific Southwest	Pacific Northwest	Total (Excluding Exports)
Percentage Distribution of Net Production to Consuming Regions											
Other Southwest	1.0%	9.8%	8.4%	6.3%	0.7%	18.7%	55.1%	--	--	--	100.0%
South Louisiana	2.3	40.1	16.5	12.6	--	2.2	26.3	--	--	--	100.0
Texas Gulf Coast	1.7	20.3	5.4	12.6	--	0.5	59.5	--	--	--	100.0
Hugoton-Anadarko	--	2.9	--	26.9	21.5	33.3	9.3	4.9%	1.2%	--	100.0
Permian Basin	--	--	--	0.5	5.0	--	31.5	--	63.0	--	100.0
Texas RR Districts 1 and 7B	0.2	12.8	3.3	1.8	0.4	--	81.5	--	--	--	100.0
San Juan Basin	--	--	--	--	--	--	--	0.1	99.9	--	100.0
Rocky Mountain	--	--	--	--	12.4	--	--	73.3	6.1	8.2%	100.0
California	--	--	--	--	--	--	--	--	100.0	--	100.0
All Other	--	90.2	--	9.8	--	--	--	--	--	--	100.0
Continental United States	1.0	18.2	6.2	11.4	4.6	8.9	32.6	3.1	13.7	0.3	100.0
Canada	--	0.5	--	16.9	1.7	--	--	6.3	37.5	37.5	100.0
Mexico	12.9	87.1	--	--	--	--	--	--	--	--	100.0
Total, including imported gas	1.1	18.0	6.0	11.5	4.5	8.6	31.7	3.2	14.2	1.2	100.0
Source of Natural Gas for Consuming Regions 1964											
Other Southwest	13.9%	7.6%	19.4%	7.7%	2.1%	30.2%	24.3%	--	--	--	14.0%
South Louisiana	46.1	49.6	61.2	24.5	--	5.6	18.5	--	--	--	22.3
Texas Gulf Coast	33.7	23.4	18.6	22.9	--	1.2	39.1	--	--	--	20.8
Hugoton-Anadarko	--	2.6	--	38.3	77.8	63.0	4.8	25.3%	1.4%	--	16.4
Permian Basin	--	--	--	0.4	10.8	--	9.7	--	43.2	--	9.8
Texas RR Districts 1 and 7B	0.2	1.0	0.8	0.2	0.1	--	3.6	--	--	--	1.4
San Juan Basin	--	--	--	--	--	--	--	0.1	19.2	--	2.7
Rocky Mountain	--	--	--	--	8.3	--	--	69.7	1.3	21.3%	3.0
California	--	--	--	--	--	--	--	--	28.4	--	4.0
All Other	--	14.1	--	2.4	--	--	--	--	--	--	2.8
Continental United States	95.9	98.3	100.0	96.4	99.1	100.0	100.0	95.1	93.5	21.3	97.2
Canada	--	0.1	--	3.6	0.9	--	--	4.9	6.5	78.7	2.5
Mexico	4.1	1.6	--	--	--	--	--	--	--	--	0.3
Total, including imported gas	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0

Source: Schedule 32.

Schedule 33

FA-946

92 e

Exhibit No. 21

[8,840]

Schedule 34

RESERVES ADDITIONS, NET PRODUCTION AND TOTAL PROVED RESERVES OF NATURAL GAS IN SOUTH LOUISIANA[a]

1956 - 1969

(Volumes in Billions of Cubic Feet at 14.73 psia)

Year	Reported Data: Reserves Additions (1)	Reported Data: Net Production (2)	Finding-Production Ratio: Annual (3)	Finding-Production Ratio: Three-Year Moving Averages[b] (4)	Total Reserves End of Year (5)	Reserves-Production Ratio (6)
1956	4,349	1,393	3.1		39,333	28.2
1957	7,902	1,587	5.0	3.6	45,647	28.8
1958	5,222	1,821	2.9	3.6	49,048	26.9
1959	7,192	2,254	3.2	2.8	53,986	24.0
1960	6,228	2,488	2.5	2.5	57,726	23.2
1961	5,415	2,771	2.0	2.5	60,370	21.8
1962	9,171	2,979	3.1	2.4	66,563	22.3
1963	7,226	3,352	2.2	2.4	70,437	21.0
1964	6,957	3,513	2.0	2.0	73,880	21.0
1965	7,798	4,008	1.9	1.7	77,670	19.4
1966	5,510	4,566	1.2	1.5	78,613	17.2
1967	8,181	5,371	1.5	1.4	81,424	15.2
1968	7,983	6,013	1.3	1.1	83,393	13.9
1969	4,165	6,789	0.6		80,769	11.9

a/ Includes offshore.

b/ Based on three-year moving averages of data in Cols. (1) and (2) centered on the middle year.

Source: Reports by the American Gas Association Committee on Natural Gas Reserves.

FA-11511

RESERVES ADDITIONS, NET PRODUCTION AND TOTAL PROVED RESERVES
OF NATURAL GAS IN THE ROCKY MOUNTAINS[a]
1956-1969
(Volumes in Billions of Cubic Feet at 14.73 psia)

Year	Reported Data: Reserves Additions (1)	Reported Data: Net Production (2)	Finding-Production Ratio: Annual (3)	Finding-Production Ratio: Three-Year Moving Average[b] (4)	Total Reserves, End of Year[c] (5)	Reserves-Production Ratio (6)
1956	830	313	2.7		7,556	24.1
1957	1,080	387	2.8	2.8	8,256	21.3
1958	1,068	365	2.9	2.7	8,958	24.5
1959	1,019	421	2.4	1.9	9,560	22.7
1960	208	437	0.5	1.7	9,348	21.4
1961	1,066	490	2.2	1.0	9,923	20.3
1962	82	449	0.2	0.9	9,585	21.3
1963	159	450	0.4	0.1	9,321	20.7
1964	(46)	478		0.3	8,812	18.4
1965	351	525	0.7	0.3	8,656	16.5
1966	207	561	0.4	0.7	8,335	14.9
1967	648	532	1.2	0.8	8,465	15.9
1968	475	540	0.9	1.0	8,420	15.6
1969	598	575	1.0		8,440	14.7

a/ Colorado, Montana, Nebraska, North Dakota, Utah and Wyoming.
b/ Based on three-year moving averages of data in Cols. (1) and (2) centered on the middle year.
c/ Includes reserves held in underground storage which showed a net increase of 9 Bcf during 1969 and a total of 241 Bcf at the end of that year.

Source: Reports by the American Gas Association Committee on Natural Gas Reserves.

Exhibit No. 21

[8,848]

Schedule 42

SOUTH LOUISIANA PRODUCING AREA a/

RESERVES AND PRODUCTION PROJECTED TO 1980 UNDER A POSITIVE PROGRAM OF BALANCING NATURAL GAS SUPPLIES IN THE U. S.

(Volumes in Billions of Cubic Feet at 14.73 psia)

Year	Reserves Additions (1)	Net Production (2)	Total Reserves End of Year (3)	Reserves-Production Ratio (4)
Historical				
1959	7,192	2,254	53,986	24.0
1960	6,228	2,488	57,726	23.2
1961	5,415	2,771	60,370	21.8
1962	9,171	2,979	66,563	22.3
1963	7,226	3,352	70,437	21.0
1964	6,957	3,513	73,880	21.0
1965	7,798	4,008	77,670	19.4
1966	5,510	4,566	78,613	17.2
1967	8,181	5,371	81,424	15.2
1968	7,983	6,013	83,393	13.9
1969	4,165	6,789	80,769	11.9
Projected				
1970	8,400	7,200	82,000	11.4
1971	8,800	7,600	83,200	10.9
1972	9,200	7,800	84,600	10.8
1973	9,700	7,900	86,400	10.9
1974	10,200	8,100	88,500	10.9
1975	10,700	8,300	90,900	11.0
1976	11,300	8,600	93,600	10.9
1977	11,800	8,900	96,500	10.8
1978	12,400	9,200	99,700	10.8
1979	13,000	9,500	103,200	10.9
1980	13,700	9,800	107,100	10.9

a/ Includes offshore.

Source: Historical data from Reports by the American Gas Association Committee on Natural Gas Reserves.

FA-11645

Exhibit No. 24

[8,873]

EXHIBIT No. 24 (JRF-1)

Witness: J. Rhoads Foster

UNITED STATES OF AMERICA
FEDERAL POWER COMMISSION

Docket No. AR69-1

IN THE MATTER OF
AREA RATE PROCEEDING
(SOUTHERN LOUISIANA AREA)

RELATIONSHIP BETWEEN FIELD PRICE OF GAS AND ACTIVITY IN THE SEARCH FOR GAS

Foster Associates, Inc.
Washington, D. C.

May 1, 1970

Exhibit No. 24

[8,874]

RELATIONSHIP BETWEEN FIELD PRICE OF GAS AND ACTIVITY IN THE SEARCH FOR GAS

Chart 1 compares the level of initial prices for new gas sales, expressed in constant dollars, and the level of exploratory drilling productive of gas. The price series represents the weighted average initial contract price under new gas sales contracts in each year. The price series are expressed in constant 1958 dollars by deflation with the implicit price index which is compiled by the U. S. Department of Commerce and which is implicit in the deflation of the gross national product to constant dollars.

The question is whether the data on prices and footage as depicted on the chart can be used to demonstrate a price-supply relationship. The available observations of price and quantity may reflect either (1) movement *along* a supply curve in response to greater demand, (2) a change in the position of the supply curve, or (3) both types of change. When one examines such a series of observations of price and quantity over time, one cannot, on *a priori* grounds, know to what extent they approximate points on a particular supply curve.

The points depicted on Chart 1 reflect neither the quantity of gas found at different prices nor the dollar cost of finding the supplies. Yet, subject to further study, they appear to provide useful information concerning elasticity of gas supplies. The reasons for this conclusion stem from an examination of the investment decision-making process in the gas producing industry.

Exhibit No. 24

[8,875]

In the typical public utility or manufacturing enterprise, the relation between investment and productive capacity, or output, is relatively certain, both *ex ante* (prospectively) and *ex post* (retrospectively). Stated differently, the results in terms of physical productivity typically confirm the expectations. By contrast, in exploration for gas, the investment decisions of management are made on the basis of careful selection of alternative opportunities with the anticipation of a particular relation between expenditures and productivity; this is the *ex ante* posture. It does not mean that management is unaware of the possibility that the expected relationship will not materialize; that is one aspect of the risk incurred in gas exploration. Viewed retrospectively, *ex post*, the relationship between footage drilled and reserve additions may be erratic, on an annual basis. In the context of the regulatory search for the supply-eliciting price, the most relevant inquiry concerns the *ex ante*, not the *ex post* relationship. The prospective relationship is best measured by reference to the physical effort made in response to a specific price level change.[1]

It is, of course, possible that an increased exploratory effort will not become translated into the proportional increase in reserve additions indicated by the analysis of the historical relationship between

[1] To relate each year's exploratory drilling to that year's prices is to implicitly assume that price change is immediately reflected in drilling activity by the managerial decision-making process, or that the prices are correctly anticipated, and to disregard certain unavoidable lags.

Exhibit No. 24

[8,876]

prices and drilling activity.[1] That will depend on a series of complex and interrelated factors determining the cost of finding supplies, including the trend in productivity of drilling and year-to-year vagaries of fortune. The Commission, however, must be concerned with providing the price stimulant. It thus follows that exploratory drilling activity provides the crucial indicator, and may be viewed as a proxy for new supplies, for the regulatory purpose of measuring the probable response of management to changes in price.

A second question concerns the relationship between initial gas prices and the cost of finding supplies. In the gas producing industry, prices operate as a limiting factor to cost incurrence and thus become cost-determining. Management will incur costs, i.e., drill prospects, up to the point where the anticipated return is equal to that of alternative opportunities. The cost-price relationship is *ex ante*, not *ex post*.

---

[1] The line on Chart 1 is of the form

$$y = ax^b$$

where y represents exploratory footage and x represents gas price. In an equation of this form, the value of b shows the percentage change in y corresponding to a one-percent change in x. The line shown in the chart was fitted to the data for 1950-1969 by the method of least squares and is represented by the following equation:

Exploratory Footage (000's) = 68.209 (Gas Price, Cents) 1.468

The expondent of gas price in the above equation—1.468—has a bearing on the elasticity of exploratory gas footage with respect to price; i.e., for every 1 percent change in price there has been, on the average, a 1.5 percent change in exploratory gas footage.

The correlation between price and footage, derived using the above equation for the period 1950-1969, is .88.

Exhibit No. 24
[8,877]

Use of initial contract prices assumes that management regarded the initial prices as prospective firm prices. The 1960's was a period of great uncertainty as to whether producers would be permitted to realize revenues equivalent to the existing guideline and in-line prices. In view of the uncertainty involved in attempting to ascertain the composite industry price "expectation," the actual initial contract price has been used in Chart 1 and Schedule 1.

Irrespective of the degree of sophistication of analysis, there can be no assurance that the price-cost relationship, or the interrelationships of the cost-determining factors, experienced in the past will prevail in the future. The uncertainty of the various interrelationships reflect risks of the business, which the Commission must share in the sense that higher prices may exceed or fall short of the anticipated increments of supply.

Exhibit No. 24

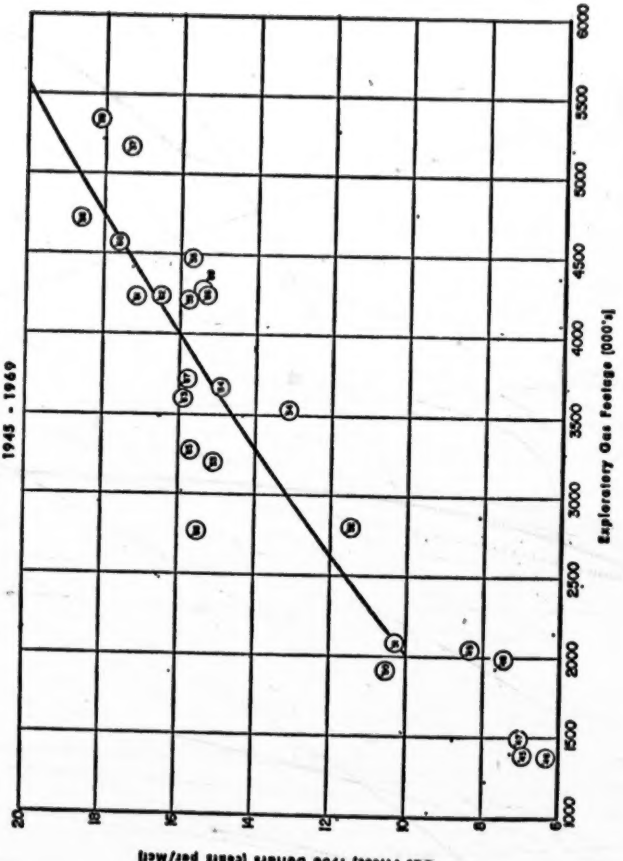
[8,878]

CHART 1

RELATIONSHIP BETWEEN INITIAL PRICE FOR NEW GAS SALES AND GAS EXPLORATORY DRILLING

SEVEN SOUTHWEST STATES,

1945 - 1969



[8,879]

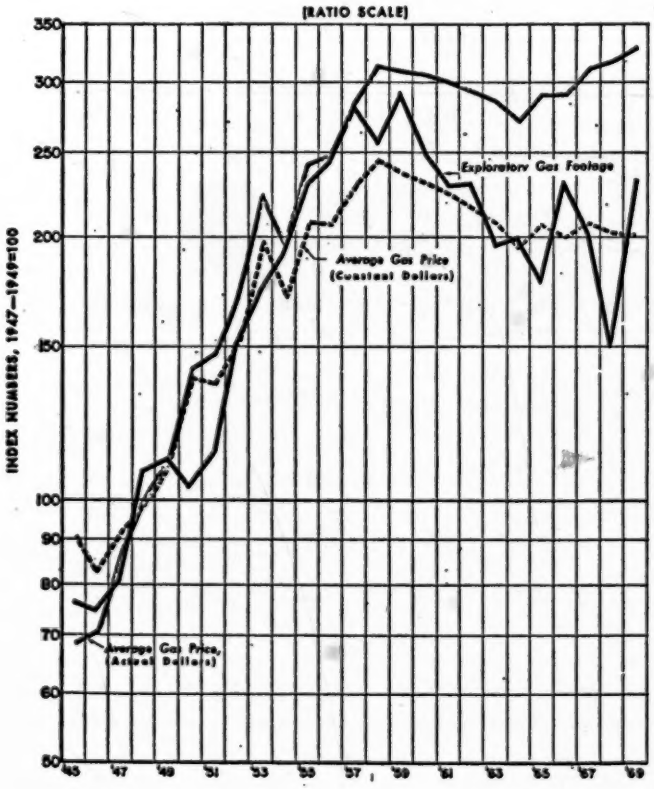
Exhibit No. 24

[8,879]

CHART 2

AVERAGE INITIAL PRICES FOR NEW GAS SALES AND EXPLORATORY DRILLING FOR GAS

SEVEN SOUTHWEST STATES
1945 - 1969



FA 11A26

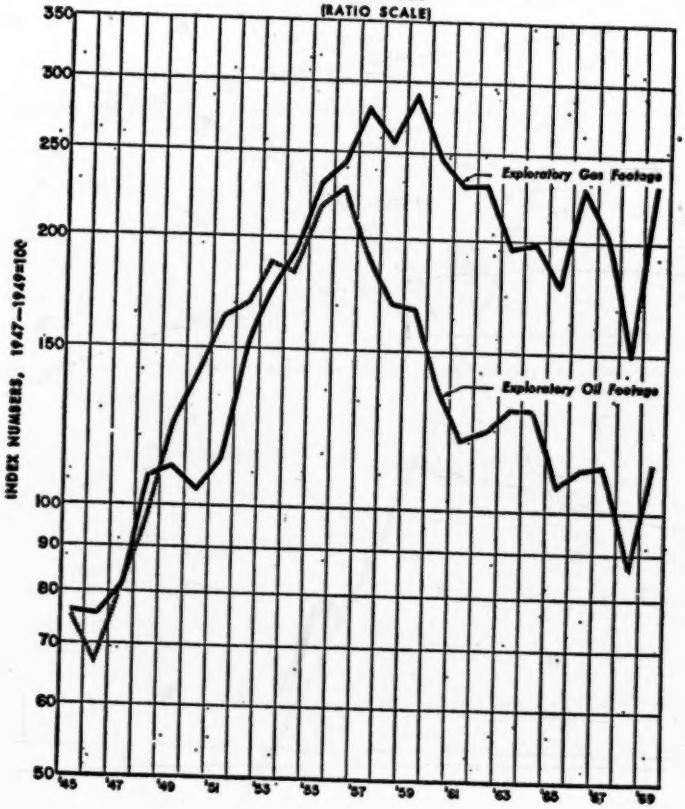
Exhibit No. 24

[8,880]

CHART 8

CHANGES IN EXPLORATORY GAS FOOTAGE AND IN EXPLORATORY OIL FOOTAGE

SEVEN SOUTHWEST STATES
1945 - 1969
(RATIO SCALE)



FA 33607

Exhibit No. 24

[8,881]

CHART 4

EXPLORATORY AND DEVELOPMENT GAS DRILLING

SEVEN SOUTHWEST STATES

1945 - 1969

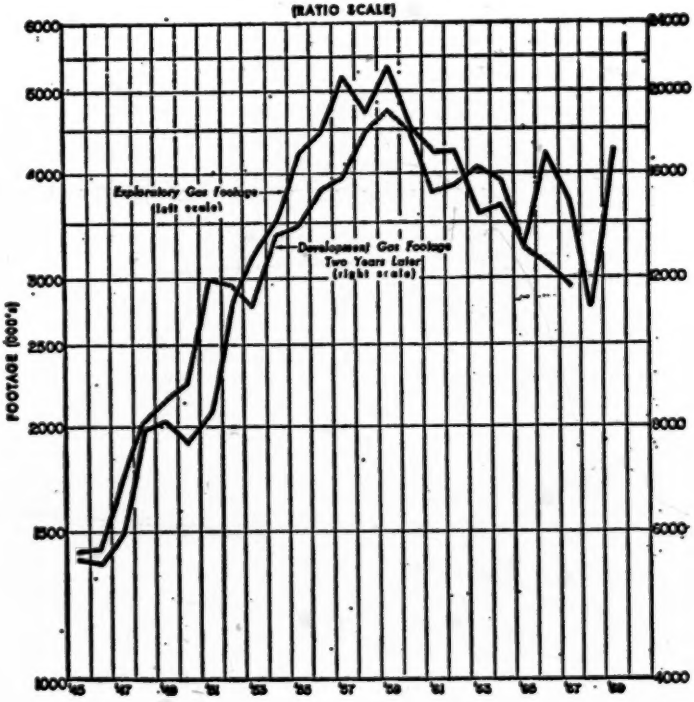


Exhibit No. 24

[8,882]

Schedule 1

WEIGHTED AVERAGE INITIAL CONTRACT PRICES FOR NEW GAS SALES
SEVEN SOUTHWEST STATES
1945-1969

Year (1)	Weighted Average Initial Price (¢/Mcf at 14.65 psia) (2)	Implicit Price Index (1958=100) (3)	Weighted Average Initial Price 1958 Dollars (¢/Mcf) (4)	Index Numbers (1947-49=100) Actual Price (5)	Index Numbers (1947-49=100) Price in Constant Dollars (6)
1945	4.1	59.7	6.9	69	91
1946	4.2	66.7	6.3	71	83
1947	5.2	74.6	7.0	88	92
1948	6.0	79.6	7.5	101	99
1949	6.6	79.1	8,3	111	109
1950	8.4	80.2	10.5	142	138
1951	8.8	85.6	10.3	148	136
1952	10.1	87.5	11.5	170	151
1953	13.3	88.3	15.1	224	199
1954	11.7	89.6	13.1	197	172
1955	14.4	90.9	15.8	243	208
1956	14.8	94.0	15.7	249	207
1957	16.9	97.5	17.3	285	228
1958	18.6	100.0	18,6	313	245
1959	18.4	101.6	18.1	310	238
1960	18.2	103.3	17.6	307	232
1961	17.9	104.6	17.1	302	225
1962	17.5	105.8	16.5	292	217
1963	17.0	107.2	15.9	287	209
1964	16.2	108.8	14.9	273	196
1965	17.4	110.9	15.7	293	207
1966	17.4	113.9	15.3	293	201
1967	18.6	117.6	15.8	313	208
1968	19.0	122.3	15.5	320	204
1969	19.7	128.1	15.4	332	203

Source: Col. (2) - Foster Associates. The series covers long-term gas sales to interstate pipeline companies and is inclusive of tax reimbursement for sales in Louisiana and Mississippi. The individual prices were weighted with initial annual volumes delivered under the contracts; for contracts dated 1967-1969, the volume weights were the estimated first-month volumes shown by the sellers in their filings with the FPC. The weighted average price data for 1945-1951 were estimated from simple averages of the individual initial contract prices.

Col. (3) U. S. Department of Commerce.

FA-11620

Exhibit No. 24

[8,883]

Schedule 2

PRODUCTIVE EXPLORATORY AND DEVELOPMENT FOOTAGE
SEVEN SOUTHWEST STATES
1945-1969

Year	Exploratory Footage Drilled				Development Footage Drilled			
	Actual (Thousands of feet)		Index Numbers (1947-49=100)		Actual (Thousands of feet)		Index Numbers (1947-49=100)	
	Gas	Oil	Gas	Oil	Gas	Oil	Gas	Oil
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1945	1,388	2,978	76	73	4,267	31,349	70	62
1946	1,377	2,712	75	67	4,950	36,351	81	72
1947	1,491	3,284	81	81	5,677	41,839	93	83
1948	1,984	3,886	108	96	5,710	53,704	94	106
1949	2,034	5,032	111	124	6,836	55,908	113	111
1950	1,911	5,695	104	140	8,103	70,622	133	140
1951	2,076	6,586	113	162	8,535	70,836	141	140
1952	2,798	6,815	152	168	8,982	71,487	148	142
1953	3,191	7,612	174	187	11,999	70,405	198	139
1954	3,520	7,418	192	182	11,758	79,025	194	157
1955	4,214	8,781	230	216	11,188	87,392	184	173
1956	4,477	9,219	244	227	13,484	86,700	222	172
1957	5,164	7,758	281	191	13,879	81,128	228	161
1958	4,720	6,892	257	169	15,278	67,712	252	134
1959	5,338	6,826	291	168	15,856	70,537	261	140
1960	4,561	5,562	248	137	17,867	62,517	292	124
1961	4,231	4,861	230	120	18,950	62,598	312	124
1962	4,232	4,967	231	122	17,952	65,444	296	130
1963	3,592	5,274	196	130	15,207	60,023	250	119
1964	3,661	5,279	199	130	15,492	58,468	255	116
1965	3,277	4,340	178	107	16,211	53,140	267	105
1966	4,240	4,520	231	111	15,687	47,562	258	94
1967	3,711	4,543	202	112	13,049	39,691	215	79
1968	2,762	3,556	150	87	12,445	37,761	205	75
1969	4,259	4,613	232	113	11,798	36,974	194	73

Source: Cols. (2) and (3) - American Association of Petroleum Geologists.
Cosl. (6) and (7) - Development footage drilled is defined as the difference between total productive footage as reported in the Annual Review - Forecast Issues of World Oil and exploratory footage drilled as reported by AAPG.

FA-11621

Exhibit No. 25

[8,906]

COMPARATIVE CHANGES IN CONSUMERS' PRICES, WHOLESALE COMMODITY PRICES, CONSTRUCTION COSTS AND OTHER PRICES

(Index Numbers: 1947-1949 = 100)

Year	Consumers' Prices	Wholesale Prices, All Commodities	Composite Construction Costs	Commerce Dept. Implicit Price Index (Gross National Product)
(1)	(2)	(3)	(4)	(5)
1939	59	50	49	56
1940	60	51	50	56
1941	63	57	54	61
1942	70	64	61	68
1943	74	67	65	73
1944	75	68	64	75
1945	77	69	67	77
1946	83	79	78	86
1947	95	96	93	96
1948	103	104	104	102
1949	102	99	103	102
1950	103	103	107	103
1951	111	115	117	110
1952	113	112	119	113
1953	114	110	122	114
1954	115	110	122	115
1955	114	111	125	117
1956	116	114	132	121
1957	120	118	138	125
1958	124	119	139	129
1959	125	119	142	131
1960	126	120	143	133
1961	128	119	144	135
1962	129	119	149	136
1963	131	119	151	138
1964	133	119	156	140
1965	135	122	161	143
1966	139	126	165	146
1967	143	126	174	151
1968	149	129	182	157
1969	157	134	196	165
1969 Jan.	152	131	190	}
Feb.	153	132	190	} 162
Mar.	154	133	192	}
Apr.	155	133	193	}
May	156	134	193	} 164
June	157	134	197	}
July	157	135	199	}
Aug.	158	135	199	} 166
Sept.	159	135	199	}
Oct.	159	135	199	}
Nov.	160	136	200	} 168
Dec.	161	137	201	}

Source: Cols. (2), (3) & (4): Business Statistics; 1967 issue and current issues, Survey of Current Business

Col. (5): U. S. Department of Commerce, Survey of Current Business. The series represents the index implicit in the comparison of gross national product in current dollars with gross national product in constant 1958 dollars.

INDEXES OF CHANGE IN PRICE AND COST
OF INPUT FACTORS REQUIRED BY THE GAS PRODUCING INDUSTRY
1947 - 1968
(1947-1949 = 100)

Year	Wholesale Prices: Casing: Carbon (1)	Wholesale Prices: Casing: Alloy (2)	Wholesale Prices: Line Pipe (Carbon) (3)	Average Hourly Earnings Petroleum Workers (4)	Cost Index of Input Factors Purchased Directly by the Well Drilling Operator (5)
1947	91.5	89.9	86.7	89.8	94.7
1948	102.4	102.6	102.9	101.7	101.6
1949	106.2	107.6	110.4	108.5	103.7
1950	116.1	111.8	116.5	110.8	109.1
1951	122.7	117.5	123.5	119.1	113.7
1952	125.1	120.4	130.8	127.4	115.7
1953	135.9	130.5	148.8	135.2	121.2
1954	144.1	140.3	157.7	138.4	124.2
1955	151.5	149.6	167.2	141.6	129.8
1956	161.7	165.2	190.7	151.3	137.3
1957	179.5	186.9	212.0	159.0	147.3
1958	187.1	194.9	218.9	163.5	148.5
1959	190.7	198.7	218.1	170.6	149.8
1960	190.7	198.7	215.9	173.1	150.9
1961	186.3	194.1	213.6	180.2	152.0
1962	183.2	190.8	214.8	182.1	152.2
1963	185.0	192.7	219.8	187.9	152.1
1964	191.3	198.7	214.8	189.9	154.9
1965	200.3	208.2	203.2	195.0	160.6
1966	200.3	208.2	203.2	201.5	163.7
1967	208.2	212.6	207.5	209.2	174.6
1968	210.7	216.7	215.5	217.5	180.6

Source: Cols. (1) - (4): U. S. Department of Labor, Bureau of Labor Statistics.

Col. (5): Reports of Independent Petroleum Association of America Cost Study Committee.

Exhibit No. 27-A

[8,933]

EXHIBIT No. 27-A
Witness: Donald W. Auten

UNITED STATES OF AMERICA
FEDERAL POWER COMMISSION

Docket No. AR69-1

IN THE MATTER OF

AREA RATE PROCEEDING
(SOUTHERN LOUISIANA AREA)

SUMMARY OF PROVED NATURAL GAS RESERVES REPORTED IN RESPONSE TO COMMISSION ORDER DATED MARCH 17, 1970 (REVISED—SEPTEMBER 28, 1970)

Exhibit No. 27-A

[8,934]

Schedule A
Page 1

REPORT OF PROVED NATURAL GAS RESERVES
AVAILABLE FOR SALE OR RESERVED FOR "COMPANY USE - WARRANTY GAS"
SOUTHERN LOUISIANA AREA, EXCLUDING FEDERAL DOMAIN

(Mcf at 14.73 psia)

Volume of Proved Reserves	Company Use-Warranty Gas	Available for Sale
As of December 31, 1968	2,598,749,372	1,269,943,375
As of December 31, 1969	1,954,232,242	1,508,980,877

Exhibit No. 27-A
[8,935]

Schedule A
Page 2

SUMMARY OF PROVED NATURAL GAS RESERVES AVAILABLE FOR SALE OR RESERVED FOR "COMPANY USE—WARRANTY GAS" SOUTHERN LOUISIANA AREA, EXCLUDING FEDERAL DOMAIN REPORTED BY INDEPENDENT PRODUCERS

Instructions: Each producer respondent who had total company-wide jurisdictional sales of 10 million Mcf or more during 1968 will report all proved gas reserves in the indicated categories in the Southern Louisiana area, excluding the Offshore Area in Zone 2 and seaward.

Proved Reserves are, using the definition of the Committee on Natural Gas Reserves of the American Gas Association, as follows:

"The current estimated quantity of natural gas which analysis of geologic and engineering data demonstrate with reasonable certainty to be recoverable in the future from known oil and gas reservoirs under existing economic and operating conditions. Reservoirs are considered proved that have demonstrated the ability to produce by either actual production or conclusive formation test.

"The area of a reservoir considered proved is that portion delineated by drilling and defined by gas-oil, gas-water, or oil-water contacts or limited by structural deformation or lenticularity of the reservoir. In the absence of fluid contacts, the lowest known structural occurrence of hydrocarbons controls the proved limits of the reservoir. The proved area of a reservoir may also include the adjoining portions not delineated by drilling

but which can be evaluated as economically productive on the basis of geological and engineering data available at the time the estimate is made. Therefore, the reserves reported by the Committee include total proved reserves which may be in either the drilled or the undrilled portions of the field or reservoir."

Consistent with procedures of the Committee on Natural Gas Reserves of the American Gas Association, Proved Reserves do not include the "portions of the reservoir hydrocarbon gas recovered in liquid form in surface separators or plant facilities."

Proved Natural Gas Reserves Available for Sale or Reserved for "Company Use—Warranty Gas" shall be reported as the reporting company's working interest (including royalty) in all proved gas reserves in the following categories:

A. Company use volumes held for fulfillment of warranty gas sales contracts but not specifically identified by field in 1968 Form 15 reports of pipelines nor to be specifically identified by field in the 1969 Form 15 reports of pipelines.

B. Volumes held "available for sale" are those which are not covered by gas purchase contracts and are not reserved for direct industrial contracts, company use-warranty gas (A above), or company use—fuel and feedstock.

TABLE S-1

SUMMARY OF PROJECTED MINIMUM SUPPLY REQUIREMENTS
SOUTH LOUISIANA (INCLUDING OFFSHORE) FOR PERIOD 1970-1977

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
	YEAR							
	1970	1971	1972	1973	1974	1975	1976	1977
1. Minimum Total Reserves Requirements, trillion cubic feet[1]	8.81	10.09	10.89	11.49	11.88	12.18	12.49	13.41
1a. Reserves Required to Sustain Previous Markets, trillion cubic feet[2]	1.54	1.79	2.14	2.92	3.67	4.41	5.94	6.64
2. Market Requirements, trillion cubic feet[3]	7.60	8.10	8.44	8.79	9.14	9.50	9.87	10.26
3. Static Deliverability Life, years	5.30	4.10	3.00	2.80	2.60	2.40	2.20	2.00
4. Required Gas Wells[4]								
Low Probable Range	759	871	924	951	950	933	1,007	1,151
High Probable Range	850	988	1,058	1,101	1,112	1,102	1,212	1,414
5. Finding to Production Ratio[5]	1.16	1.25	1.29	1.31	1.30	1.28	1.27	1.31
6. Reserves to Production Ratio[6]	10.79	10.37	10.24	10.14	10.05	9.95	9.84	9.78

(1) HJG-1, Column 2, Table II-1, page 12.
(2) Column 4, HJG-1, Table I-1, page 5.
(3) Furnished by Stanford Research Institute
(4) Includes dry holes. See HJG-3, Table 1, page 2.
(5) Item (1.) above, divided by Item (2.) above.
(6) Column 9, HJG-1, Table II-1, page 12.

Docket No. AR69-1
Exhibit HJG-1, Table b
Witness: H. J. Gray

Exhibit No. 28

[8,953]

[8,953]

118 e

[8,998]

Exhibit No. 30

[8,998]

114 e

Docket No. AR69-1
Exhibit HJG-3, Table I
Witness: H. J. Gray

TABLE I

PROJECTED GAS WELLS REQUIRED TO DEVELOP REQUIRED GAS RESERVES IN SOUTH LOUISIANA FOR THE PERIOD 1970-1977

(Reserve Figures in Mmcf)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)
	REQUIRED RESERVES						PROJECTED RESERVES ADDED PER WELL DRILLED FOR GAS(4)				REQUIRED NUMBER OF WELLS(5)(6) TO BE DRILLED FOR GAS					
	Onshore Including Zone 1		Offshore Zones 2, 3 and 4		Total South Louisiana		Onshore Including Zone 1		Offshore Zones 2, 3 and 4		Onshore Including Zone 1		Offshore Zones 2, 3 and 4		Total	
Year	Non-Associated	Total	Non-Associated	Total	Non-Associated	Total(1)	Upper Range Probable	Lower Range Probable	Upper Range Probable	Lower Range Probable	Low Probable Range	High Probable Range	Low Probable Range	High Probable Range	Low Probable Range	High Probable Range
1970	3,886,000	4,328,000	3,730,000	4,494,000	7,316,000	8,814,000	6,625	5,813	27,125	16,000	541	617	218	233	759	850
1971	4,025,000	4,849,000	4,348,000	5,238,000	8,372,000	10,087,000	6,500	5,625	27,750	16,000	619	716	252	272	871	988
1972	4,070,000	4,904,000	4,965,000	5,982,000	9,035,000	10,886,000	6,375	5,438	27,375	16,000	638	748	286	310	924	1,058
1973	3,950,000	4,759,000	5,581,000	6,726,000	9,531,000	11,485,000	6,250	5,250	27,500	16,000	632	753	319	349	951	1,101
1974	3,664,000	4,414,000	6,200,000	7,470,000	9,864,000	11,884,000	6,125	5,063	27,625	16,000	598	724	352	388	950	1,112
1975	3,294,000	3,969,000	6,818,000	8,214,000	10,112,000	12,183,000	6,000	4,875	27,750	16,000	549	676	384	436	933	1,112
1976	3,735,000	4,500,000	6,432,000	7,750,000	10,167,000	12,490,000	5,875	4,688	27,875	16,000	636	797	371	418	1,007	1,215
1977	4,496,000	5,417,000	6,616,000	7,995,000	11,112,000	13,412,000	5,750	4,500	28,000	16,000	782	999	369	418	1,151	1,416

(1) Total South Louisiana minimum Required Reserves to Support Market projected by Stanford Research Institute. See Column 2, Exhibit HJG-1, Table II-1, page 12.

(2) South Louisiana Offshore (Zones 2, 3 and 4) minimum Required Reserves to Support Market allocated portion of Total Area Market. See Column 2, Exhibit HJG-2, Table II-1, page 12.

(3) Difference between Total Area and Non-Area.

(4) From Figure 1, Exhibit HJG-3.

(5) Required Number of Wells to be drilled for gas includes allocated non-productive wells.

(6) Low probable range calculated using the upper range projection of reserves added per well drilled. High probable range calculated using the lower range projection of reserves added per well drilled.

Exhibit No. 31

[9,005]

Exhibit No. 31-A

[9,015]

Exhibit No. 42

[9,349]

EXHIBIT No. 42 (CMA-4)
Witness: C. M. Allen

UNITED STATES OF AMERICA
FEDERAL POWER COMMISSION

Docket Nos. AR69-1, *et al.*....

IN THE MATTER OF

AREA RATE PROCEEDING
(SOUTHERN LOUISIANA AREA)

DATA RELATIVE TO THE PREDICTIVE ACCURACY IN THE SEPARATE SEARCH FOR OIL AND FOR GAS

July 1970

[9,350]

Exhibit No. 42

[9,350]

TOTAL EXPLORATORY

(1)	Predicted Wells Which Were Subsequently Productive			Productive Wells Predicted Correctly			Percentage Accuracy		
	Oil (2)	Gas (3)	Total (4)	Oil (5)	Gas (6)	Total (7)	Oil (8)	Gas (9)	Total (10)
1949-1957	112	48	160	81	48	129	72.3%	100.0%	80.6%
1958	103	42	145	97	37	134	94.2	88.1	92.4
1959	133	118	251	115	111	226	86.5	94.1	90.0
1960	88	125	213	80	115	195	90.9	92.0	91.5
1961	209	313	522	183	256	439	87.6	81.8	84.1
1962	323	285	608	290	238	528	89.8	83.5	86.8
1963	377	275	652	327	235	562	86.7	85.5	86.2
1964	376	315	691	329	256	585	87.5	81.3	84.7
1965	350	288	638	300	256	556	85.7	88.9	87.1
1966	370	292	662	307	244	551	83.0	83.6	83.2
1967	309	259	568	269	222	491	87.1	85.7	86.4
1968	315	244	559	271	202	473	86.0	82.8	84.6
1969	226	247	473	196	219	415	86.7	88.7	87.7
TOTAL	3,291	2,851	6,142	2,845	2,439	5,284	86.4	85.5	86.0

(GM-4) Schedule 1

Exhibit No. 42

TOTAL NEW FIELDS

(1)	Predicted Wells Which Were Subsequently Productive: Oil (2)	Gas (3)	Total (4)	Productive Wells Predicted Correctly: Oil (5)	Gas (6)	Total (7)	Percentage Accuracy: Oil (8)	Gas (9)	Total (10)
1949-1957	74	13	87	54	13	67	73.0%	100.0%	77.0%
1958	79	32	111	74	28	102	93.7	87.5	91.9
1959	87	94	181	80	89	169	92.0	94.7	93.4
1960	50	92	142	45	85	130	90.0	92.4	91.5
1961	95	136	231	86	117	203	90.5	86.0	87.9
1962	102	137	239	90	116	206	88.2	84.7	86.2
1963	106	80	186	94	65	159	88.7	81.3	85.5
1964	108	135	243	88	111	199	81.5	82.2	81.9
1965	104	95	199	86	85	171	82.7	89.5	85.9
1966	104	111	215	90	97	187	86.5	87.3	87.0
1967	82	77	159	70	70	140	85.4	90.9	88.1
1968	94	69	163	78	60	138	83.0	87.0	84.7
1969	82	53	142	76	47	121	85.4	88.7	86.6
TOTAL	1,174	1,124	2,298	1,011	983	1,994	86.1	87.5	86.8

(CRA-4)
Schedule 2

[9,351]

TOTAL NEW POOLS & EXTENSIONS

(1)	Predicted Wells Which Were Subsequently Productive: Oil (2)	Gas (3)	Total (4)	Productive Wells Predicted Correctly: Oil (5)	Gas (6)	Total (7)	Percentage Accuracy: Oil (8)	Gas (9)	Total (10)
1949-1957	7	31	38	6	31	37	85.7%	100.0%	97.4%
1958	21	9	30	21	8	29	100.0	88.9	96.7
1959	35	21	56	28	19	47	80.0	90.5	83.9
1960	30	27	57	28	25	53	93.3	92.6	93.0
1961	69	92	161	60	80	140	87.0	87.0	87.0
1962	142	63	205	129	57	186	90.8	90.5	90.7
1963	161	91	252	141	80	221	87.6	87.9	87.7
1964	121	99	220	110	84	194	90.9	84.8	88.2
1965	98	91	189	85	82	167	86.7	90.1	88.4
1966	122	72	194	107	69	176	87.7	95.8	90.7
1967	112	79	191	100	74	174	89.3	93.7	91.1
1968	149	92	241	133	85	218	89.3	92.4	90.4
1969	58	76	134	51	72	121	87.9	94.7	91.8
TOTAL	1,125	843	1,968	999	766	1,765	88.8	90.9	89.7

(CM4-4) Schedule 3

Exhibit No. 42

[9,353]

(CMA-4)
Schedule 4

REPORTING OF DIRECTIONAL SEARCH DATA

Proceeding	Number Companies	Number Wells (Predicted and Subsequently Productive)	Predictive Accuracy	Source
Permian (AR61-1)	5	986	87%	Exh. 239
Southern Louisiana (AR61-2)	7	1,231	87%	Exh. 45, p. 7
Hugoton-Anadarko-Texas Gulf Coast (AR64-1 and AR64-2)	12	2,255	85%	Exh. 1-J, p. 7
Other Southwest (AR67-1)	13	2,479	85%	Exh. 7, Sch. 4/
Southern Louisiana (AR69-1)	22	6,142	86%	Exh. 42 (CMA-4), Sch. 1

4/ Exh. 1-J, p. 7 from AR64-1 and AR64-2 was incorporated by reference into AR67-1. The data shown there, when added to the data for one company presented in Exh. 7, Sch. 4 yield the numbers shown for AR67-1.

Exhibit No. 46

[9,561]

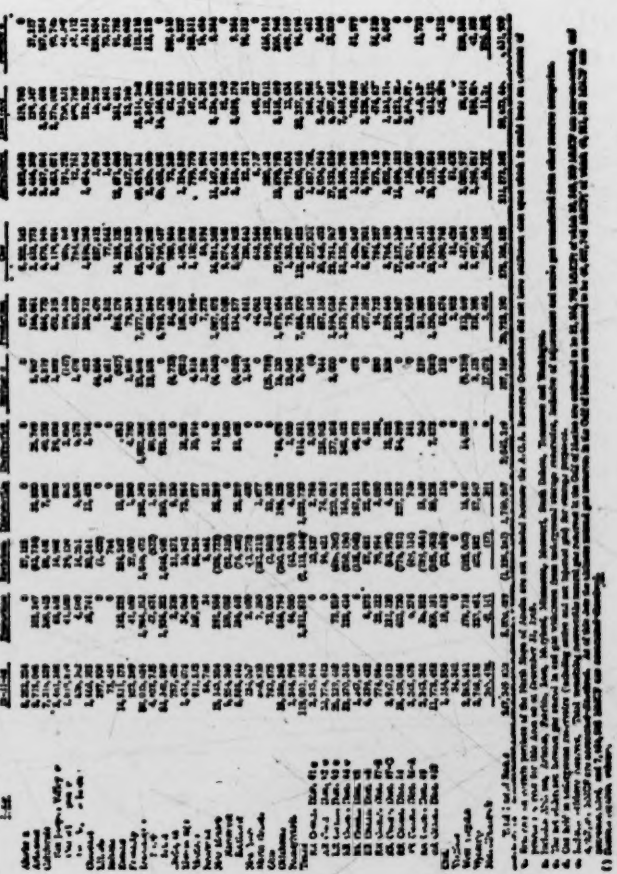
2. *The Relationship*

The behavior of ass.-dis. revisions in '68 has been characterized as anamolous, since they have been accompanied by positive rather than negative revisions of crude oil.[1] The idea is that since oil and ass.-dis. gas occur together, one would expect the gas revisions to be accompanied by oil revisions in the same direction. This rests on the assumption that there is a fixed or a stable gas oil ratio. I have already commented on this point, but whatever the case may be, the argument (Netschert's) does not hold in the case of revisions, because in a sense oil and ass.-dis. revisions are substitutes. Higher oil price (relative to ass.-dis. price) should encourage sweeping more oil at the expense of gas. This means that we should expect negative ass.-dis. revisions to be associated with positive rather than negative oil revisions. Other things being equal, revisions in both oil and ass.-dis. may be expected to move in the same direction only if oil and ass.-dis. price move in the same direction.

[1] Bruce C. Netschert, *Statement before the Subcommittee on Minerals, Materials, and Fuels*, Committee on Interior and Insular Affairs, U.S. Senate, November 12, 1969, pp. 10-11.

Exhibit No. 49

[9,991]



[9,992]

Exhibit No. 49

[9,992]

TABLE II

ESTIMATED TOTAL PROVED RECOVERABLE RESERVES OF NON-ASSOCIATED NATURAL GAS IN THE UNITED STATES

(Billions of Cubic Feet - 14.73 psia, at 60°F.)

Area	Reserves as of 12-31-68	Changes in Reserves During 1969				Preliminary Net Production	Reserves as of 12-31-69
		Extensions	Revisions	New Field Discoveries	New Reservoir Discoveries		
Alaska c	4,979,055	0	(90,000)	0	0	76,668	4,892,387
Arkansas	2,509,768	150,489	(61,248)	22,500	24,854	140,396	2,466,269
California c	9,533,627	68,190	30,331	7,000	25,500	295,335	9,357,084
San Joaquin Valley	3,797,678	63,190	21,246	500	25,500	294,243	3,853,871
Coastal Region b	227,644	0	(967)	0	0	25,748	191,229
Los Angeles Basin b	8,985	0	(257)	6,500	0	1,347	13,781
Colorado	1,538,168	18,200	(13,782)	9,877	1,754	51,748	1,454,969
Florida	2,551	0	(82)	0	0	189	2,280
Indiana	1,731	0	0	0	0	85	1,646
Kansas	14,194,611	224,959	225,557	35,819	653	695,498	13,971,665
Kentucky	836,718	41,660	27,990	1,200	4,780	74,141	837,257
Louisiana b	72,364,323	1,691,364	800,169	225,240	956,048	4,189,735	69,429,141
North	2,085,269	42,880	25,276	1,441	78,946	408,004	2,824,408
South	69,279,054	1,648,526	675,613	253,799	829,302	3,781,641	66,602,535
Michigan	77,376	1,044	4,145	5,967	0	15,163	73,268
Mississippi	1,259,252	18,000	26,226	66,792	14,000	132,439	1,134,539
Missouri	879,572	164,643	68,221	272	30,914	30,752	779,770
Nebraska	30,674	0	(12)	0	0	2,925	27,734
New Mexico	11,797,749	137,452	(110,858)	22,999	27,458	727,341	11,147,421
Northwest	9,457,433	104,314	(71,462)	0	540	541,190	8,949,535
Southeast	2,340,316	33,138	(74,997)	22,999	26,918	179,731	2,168,494
New York	27,477	2,400	(1,270)	400	0	4,756	22,971
North Dakota	4,376	0	887	0	0	226	5,737
Ohio	343,344	11,000	0	22,200	0	40,098	296,346
Oklahoma	14,434,430	713,239	(205,370)	178,718	83,799	1,131,434	13,870,782
Pennsylvania	844,498	44,000	(43,000)	4,000	1,000	79,689	771,809
Texas b	84,493,348	1,258,344	(1,730,095)	994,228	783,414	5,685,618	80,023,621
RR Comm. Dists. 01	1,979,930	0	(8,128)	2,184	3,063	122,468	1,857,781
RR Comm. Dists. 02 b	8,261,462	0	81,891	65,297	154,283	527,869	8,034,964
RR Comm. Dists. 03 b	25,902,196	48,744	(657,946)	199,077	261,846	1,302,473	23,532,526
RR Comm. Dists. 04 b	24,096,158	225,287	(271,532)	277,077	254,648	1,367,448	23,263,748
RR Comm. Dists. 05	1,353,415	0	(80,927)	246,748	48,972	84,534	1,212,998
RR Comm. Dists. 06	6,839,085	5,827	229,853	27,100	5,744	348,030	6,759,479
RR Comm. Dists. 07-B	273,284	21,306	15,461	0	200	46,743	273,118
RR Comm. Dists. 07-C	2,078,290	89,642	(78,484)	4,024	24,219	304,982	2,402,799
RR Comm. Dists. 08	12,444,684	545,138	(779,509)	225,118	58,025	792,288	11,696,163
RR Comm. Dists. 08-A	135,351	1,370	(309)	0	0	6,788	129,627
RR Comm. Dists. 09	1,802,500	27,282	(233,518)	11,050	0	113,851	1,493,463
RR Comm. Dists. 010	11,044,796	291,208	(252,699)	24,277	7,797	1,027,825	10,119,554
Utah	697,701	14,454	(59,442)	0	0	28,343	644,340
Virginia	24,341	0	0	0	0	2,958	21,478
West Virginia	2,778,543	277,880	(225,329)	14,140	14,588	332,219	2,527,917
Wyoming	3,249,248	270,748	64,241	24,171	0	234,498	3,248,851
Miscellaneous c	36,148	43,990	(764)	0	0	2,547	66,727
Total United States	230,990,299	4,781,027	(1,640,196)	1,663,266	1,863,031	21,971,728	211,573,203

a. Reserves in certain portions of the North Slope of Alaska are not included because the A.G.A. Reserves Committee did not have sufficient data upon which it could base an estimate of proved reserves for this area as of December 31, 1969.

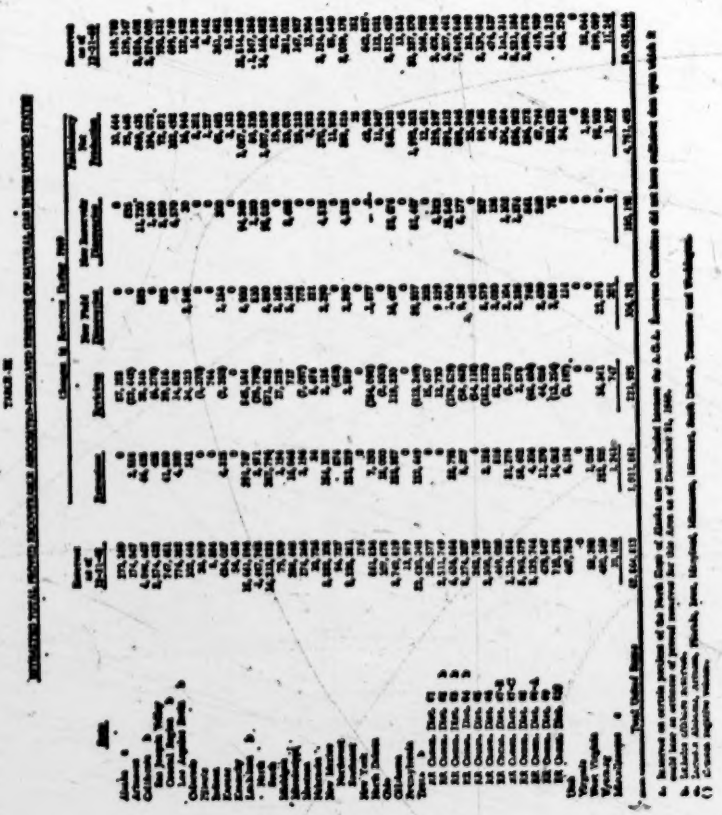
b. Includes offshore reserves.

c. Includes Alabama, Arizona, Florida, Iowa, Maryland, Minnesota, Missouri, South Dakota, Tennessee and Washington.

( ) Denotes negative volume.

Exhibit No. 49

[9,993]



[9,994]

Exhibit No. 49

[9,994]

TABLE 19

ESTIMATED TOTAL PROVED RECOVERABLE RESERVES OF NATURAL GAS LIQUIDS IN THE UNITED STATES

(Thousands of Barrels of 42 U.S. Gallons)

State	Reserves as of 12-31-48	Changes in Reserves During 1949: Extensions	Revisions	New Field Discoveries	New Reservoir Discoveries	Preliminary Net Production	Reserves as of December 31, 1949: Total Natural Gas Liquids	New Annexated	Annexated-Undrilled
Alaska	0	0	448	0	0	72	376	0	376
Arkansas	12,096	0	(43)	1,782	0	1,644	12,191	9,466	2,725
California a	205,148	800	2,822	0	280	20,757	188,293	7,364	178,548
San Joaquin Valley	96,528	0	1,259	0	0	9,482	88,305	489	87,816
Coastal Region a	69,100	800	408	0	280	5,506	64,082	6,875	57,207
Los Angeles Basin a	87,540	0	1,254	0	0	5,769	82,025	0	82,025
Colorado	22,851	999	(1,560)	0	0	1,111	19,979	6,448	13,277
Illinois	1,996	0	(26)	0	0	290	1,672	8	1,664
Indiana	44	0	4	0	0	8	40	8	32
Kansas	270,856	5,079	14,872	276	17	18,957	268,261	241,173	6,088
Kentucky	12,444	0	0	0	0	2,481	10,963	10,963	0
Louisiana	2,667,530	51,081	62,364	4,218	56,227	227,977	2,570,298	2,161,699	407,599
North	154,062	679	0	30	930	17,574	119,787	58,206	61,581
South	2,513,468	50,402	62,099	4,188	55,297	210,403	2,450,511	2,104,694	345,817
Michigan	2,598	88	1,278	216	0	1,188	4,056	1,575	2,481
Mississippi	19,578	0	1,569	767	213	2,113	20,045	13,161	6,884
Montana	9,783	0	1,253	0	0	1,255	9,881	1,491	8,390
Nebraska	2,068	0	721	0	0	529	2,260	1,071	1,189
New Mexico	804,168	35,710	22,224	276	697	66,276	796,675	572,424	227,251
Northwest	228,478	2,011	188	0	0	15,068	215,631	214,996	1,635
Southeast	575,668	6,699	22,139	276	697	51,208	584,044	58,228	225,916
North Dakota	61,563	0	(7,439)	0	0	2,529	51,654	0	51,654
Ohio	323	0	(313)	0	0	6	0	0	0
Oklahoma	446,033	16,780	24,708	4,615	2,082	43,664	485,094	352,058	133,036
Pennsylvania	1,064	0	0	0	0	90	974	974	0
Texas a	4,008,373	29,751	(75,236)	27,497	11,494	227,140	3,681,939	2,686,187	1,295,752
RR Comm. Dist. #1	85,094	0	302	28	0	2,259	83,238	36,399	6,839
RR Comm. Dist. #2 a	319,429	0	990	808	1,146	14,368	307,885	128,466	39,158
RR Comm. Dist. #3 a	355,577	926	(5,974)	2,256	2,496	25,359	745,518	335,331	207,487
RR Comm. Dist. #4 a	731,113	2,560	7,543	5,795	6,585	25,244	676,451	327,790	238,661
RR Comm. Dist. #5	22,037	0	7,417	4,963	549	6,958	27,813	18,040	9,823
RR Comm. Dist. #6	468,230	854	(2,709)	456	31	23,257	453,951	219,221	234,629
RR Comm. Dist. #7-B	44,130	956	14,496	282	18	7,900	52,981	8,979	43,923
RR Comm. Dist. #7-C	162,167	9,137	(133)	51	288	16,900	154,527	79,754	74,793
RR Comm. Dist. #8	625,348	4,296	15,458	1,706	879	65,493	565,996	325,398	240,641
RR Comm. Dist. #8-A	251,096	246	(6,248)	0	9	20,474	222,707	290	222,317
RR Comm. Dist. #9	75,818	1,703	999	216	36	9,258	69,700	34,178	35,422
RR Comm. Dist. #10	486,748	9,797	(354,913)	1,020	548	38,545	344,255	316,280	28,075
Utah	43,475	0	854	0	0	2,730	41,599	1,327	37,452
West Virginia	23,227	2,255	0	0	0	5,681	21,234	21,234	0
Wyoming	84,349	2,224	16,448	25	0	8,127	294,419	22,297	46,068
Miscellaneous b	1,227	2,488	0	0	0	982	7,133	6,378	755
Total United States	8,205,108	104,115	104,192	34,851	41,190	725,963	8,163,174	5,416,898	2,724,276

a. Includes offshore reserves
b. Alabama only
( ) Denotes negative volume

Total remaining recoverable Natural Gas Liquids resources in the Gulf of Mexico are estimated to be 845,225,000 bbls of which 740,775,000 bbls. are Non-Associated and 79,554,000 bbls. are Associated-Dissolved.

Exhibit No. 49

[9,995]

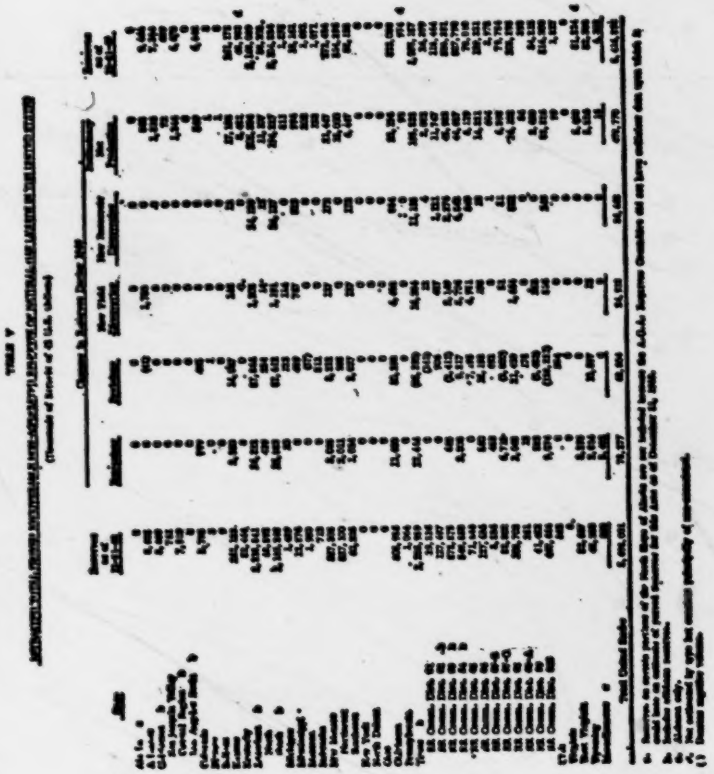


Exhibit No. 49

[9,996]

TABLE VII

SUMMARY OF ANNUAL ESTIMATES OF NATURAL GAS RESERVES IN THE UNITED STATES FOR PERIOD DECEMBER 31, 1945 TO DECEMBER 31, 1969

TOTAL ALL TYPES

(Millions of Cubic Feet - 14.73 psia, at 60°F)

	Natural Gas Added During Year								
Year	Extensions	Revisions	New Field Discoveries	New Reservoir Discoveries	Total of Discoveries, Revisions and Extensions	Net Change in Underground Storage	Preliminary Net Production During Year	Est. Proved Reserves as of Year-End	Increase Over Previous Year
1945								146,986,723	
1946		a		a	17,632,866	a	4,915,774	159,703,813	12,717,090
1947	7,529,538		3,391,649		10,921,187	a	5,599,235	165,025,765	5,321,952
1948	9,716,426		4,106,664		13,823,090	51,202	5,975,001	172,925,056	7,899,291
1949	8,017,797		4,587,818		12,605,615	82,146	6,211,124	179,401,693	6,476,637
1950	9,123,637		2,861,724		11,985,361	52,935	6,855,244	184,584,745	5,183,052
1951	12,942,930		3,022,878		15,965,808	132,030	7,923,673	192,758,910	8,174,165
1952	8,885,950		5,381,656		14,267,606	197,766	8,592,716	198,631,566	5,877,656
1953	13,298,733		7,043,200		20,341,933	213,629[b]	9,188,365	210,298,763	11,667,197
1954	4,607,155		4,939,919		9,547,074	90,408	9,375,314	210,560,931	262,168
1955	16,209,607		5,688,009		21,897,616	87,164	10,063,167	222,482,544	11,921,613
1956	19,110,251		5,605,864		24,716,115	153,241	10,848,685	236,483,215	14,000,671
1957	11,057,932		8,950,119		20,008,051	178,761	11,439,890	245,230,137	8,746,922
1958	13,316,100		5,580,624		18,896,724	57,582	11,422,651	252,761,792	7,531,655
1959	14,852,004		5,769,245		20,621,249	160,453	12,373,063	261,170,431	8,408,639
1960	7,293,015		6,600,963		13,893,978	281,273	13,019,356	262,326,326	1,155,895
1961	10,258,692		6,907,729		17,166,421	159,544	13,378,649	266,273,642	3,947,316
1962	13,184,794		6,299,164		19,483,958	159,231	13,637,973	272,278,858	6,005,216
1963	12,586,733		5,577,934		18,164,667	253,733	14,546,025	276,151,233	3,872,375
1964	13,342,838		6,909,301		20,252,139	195,110	15,347,028	281,251,454	5,100,221
1965	14,775,570		6,543,709		21,319,279	150,483	16,252,293	286,468,923	5,217,469
1966	9,224,745	4,937,962	2,947,829	3,110,396	20,220,432	134,523	17,491,073	289,332,805	2,863,882
1967	9,538,584	6,570,578	3,170,520	2,524,651	21,804,333	151,403	18,380,838	292,907,703	3,574,898
1968	7,758,821	3,016,146	1,376,429	1,545,612	13,697,008	118,569	19,373,428	287,349,853	(5,557,851)
1969	5,650,459	(1,238,261)	1,769,357	2,043,219	8,375,004	107,169	20,723,190	275,108,835	(12,241,017)

a - Not estimated.

b - All native gas in storage reservoirs formerly classified as a natural gas reserve is included in this figure.

c - Separation of revisions from extensions and of new field discoveries from new reservoir discoveries not available prior to 1966.

( ) Denotes negative volume.

[19,997]

Exhibit No. 49

[19,997]

129 e

[illegible]

Exhibit No. 51

[10,182]

EXHIBIT No. 51

Witness: Charles A. Larson

UNITED STATES OF AMERICA
FEDERAL POWER COMMISSION

Docket Nos. AR61-2 and AR69-1

IN THE MATTER OF

AREA RATE PROCEEDING, *et al.*:
SOUTHERN LOUISIANA AREA

CONTINENTAL UNITED STATES

Basic Data for the
Exploration and Development Cost Function
1960, 1962 and 1969

COMMONWEALTH
SERVICES • INC.

Exhibit No. 51

Exhibit 51
Schedule 1
Sheet 1 of 2

CONTINENTAL UNITED STATES
Exploration and Development Expenses
1960, 1962 and 1969

		1960 (A)	1962 (B)	1969 (C)
		(000 Dollars)		
(1)	Exploration Dry Holes	$ 185,966	$ 208,369	$ 295,615
(2)	Development Dry Holes	107,547	133,727	136,379
(3)	Exploration and Development Dry Holes Combined	26,809		
(4)	Unclassified Dry Holes		19,711	
(5)	Test Well Contributions	28,645	25,086	13,281
(6)	Exploration and Development and Test Well Contributions Combined	5,648		
(7)	Land Department Expense	58,512	71,667	55,345
(8)	Geological and Geophysical Expense	200,088	216,180	233,749
(9)	Land Department and Geophysical Expense Combined	16,106		
(10)	Geological and Geophysical Expenses and Depreciation, Exploration and Development Equipment and Facilities Investment Combined.	4,006		
(11)	Cancelled, Surrendered and Abandoned Leases (including Applicable Capitalized Geological, Geophysical and other Costs).	197,928		
(12)	Cancelled, Surrendered and Abandoned Leases.		205,301	
(13)	Cancelled, Surrendered and Abandoned Non-Producing Acreage (Including Applicable Capitalized Geological and Geophysical and other Costs.			142,077
(14)	Amortization of Non Producing Leases.	59,348	97,865	235,947
(15)	Cancelled, Surrendered and Abandoned Leases (Including Applicable Capitalized Geological, Geophysical and Other Costs) and Amortization of Nonproducing Leases Combined.	23,834		
(16)	Lease Rentals and Options.	118,826	136,032	86,525
(17)	Depreciation on Exploration and Development Equipment and Facilities Investment	6,351	6,112	20,845
(18)	Other Exploration and Development Costs and Expenses not included above.	22,836	23,211	58,446
(19)	Depreciation, Exploration and Development Equipment and Facilities Investment and Other Exploration and Development Costs and Expenses not Included above Combined.	183		
(20)	Other	33		
(21)	Subtotal	$ 1,062,774	1,133,261	1,277,909
(22)	Corporate General	90,63[illegible]	62,256	97,385
(23)	Area, District, Division, & Field	47,82[illegible]	85,743	76,107
(24)	(Gains) or Losses - Sales of Assets	(3,882)		
(25)	Net Profits Disbursements	(4)		
(26)	Other (Specify)		2,224	
(27)	Total	$ 1,197,[illegible]	1,283,484	1,451,401

Exhibit No. 51

[10,184]

Schedule 1
Sheet 2 of 2

SOURCE:

Column (A)—

Area Rate Proceedings, Docket No. AR 61-2, Exhibit 115, Part E, Schedule 10.

Column (B)—

Area Rate Proceedings, Docket No. AR 64-2. Sum of Exhibit No. 49J, Schedule 6, Lines 1-21 and Exhibit No. 50J, Schedule 6, Lines 1-20.

Column (C)—

1969 Questionnaire Responses, Composite of Independent Producers and Pipeline Affiliates and Natural Gas Pipeline Companies, Docket No. AR 69-1, Packet D, Schedule 3, Continental U.S., Column (F).

CONTINENTAL UNITED STATES
Exploration and Development Rate Base and Return
1960, 1962 and 1969

		1960 (A)	1962 (B)	1969 (C)
		(000 Dollars)		
	Net Investment:			
(1)	Non-Producing Acreage	1/	$1,743,503	$2,092,155
(2)	Buildings & Facilities	1/	4,396	1/
(3)	Equipment (Including Transportation Equipment)	1/	41,561	1/
(4)	Other Exploration and Development	1/		$662,545
(5)	Subtotal Exploration Net Investment	$1,464,045	1,789,460	2,754,700
(6)	Incomplete Construction	35,236	35,574	1/
(7)	Corporate General	20,137	24,887	43,161
(8)	Area, District, Division and Field	13,452	15,414	62,353
(9)	Total Net Investment	$1,532,870	$1,865,335	$2,860,214
(10)	Materials & Supplies	25,668	14,273	19,141
(11)	Prepayments	17,498	20,275	21,785
(12)	1/8 Cash Expense	109,223	118,051	131,604
(13)	Total Rate Base	$1,685,258	$2,017,934	$3,032,744
(14)	Return @ 12%	$ 202,231	$ 242,152	
(15)	Return @ 13%			$ 394,257

1/Detail not available.

Exhibit No. 51
Schedule 2
Sheet 1 of 2

[10,185]

[10,185]

133 e

Exhibit No. 51

[10,186]

Schedule 2
Sheet 2 of 2

SOURCE:

Column A—

Lines 1-13—Area Rate Proceedings, Docket No. AR61-2, Exhibit 115, Part E, Schedule 11.
Line 14—Line 13 times 12%

Column B—

Lines 1-9—Area Rate Proceedings, Docket Nos. AR64-1 and AR64-2, Exhibit No. 49J, Schedule 7, Lines 1-19 plus Exhibit No. 50J, Schedule 7, Lines 1-22.

Line 10—*Ibid.*, Exhibit No. 495, Schedule 6, Line 30 plus Exhibit No. 50J, Schedule 6, Line 29.

Line 11—*Ibid.*, Exhibit No. 49J, Schedule 6, Line 31 plus Exhibit No. 50J, Schedule 6, Line 30.

Line 12—*Ibid.*, Exhibit No. 49J, Schedule 6, Line 29 plus Exhibit No. 50J, Schedule 6, Line 28.

Line 13—Sum of lines 10-13.
Line 14—Line 13 times 12%

Column C—

1969 Questionnaire Responses, Docket No. AR 69-1, Packet D, Schedule 3, Continental J.S., Col. (f).
Lines 1-11—Lines 1-9
Line 12—(Line 23 Less Lines 15, 16 and 18) times 1/8.
Line 13—Sum of lines 10-13.
Line 15—Line 13 times 13%

Exhibit 51
Schedule 3
Sheet 1 of 1

CONTINENTAL UNITED STATES
Production Volumes and Unit Btu for Allocation of Exploration and Development Costs
1960, 1962 and 1969

		3/ 1960 (A)	3/ 1962 (B)	4/ 1969 (C)	1/ Unit Btu (D)
	Volumes				
	Oil Only:				
(1)	Crude Oil (000 Bbls)	329,334	233,761	279,490	5.846
(2)	Oil Well Gas (MMcf)	41,919	5,644	12,029	1.163
	Oil Casinghead:				
(3)	Crude Oil (000 Bbls)	710,646	803,601	1,038,947	5.818
(4)	Oil Well Gas (MMcf)	1,378,932	1,392,434	1,713,213	1.261
	Gas Only:				
(5)	Condensate (000 Bbls)	52	2	0	5.240
(6)	Gas Well Gas (MMcf)	805,939	1,470,439	1,768,378	1.036
	Gas Condensate:				
	Lse Sep:				
(7)	Condensate (000 Bbls)	52,225	65,050	89,106	5.395
(8)	Gas Well Gas (MMcf)	2,693,656	3,459,613	5,319,091	1.081
	No Lse Sep:				
(9)	Consensate (000 Bbls)	771	1	0	5.498
10)	Gas Well Gas (MMcf)	592,055	638,550	712,655	1.140
	Combination:				
	Oil Wells:				
11)	Crude Oil (000 Bbls)	207,841	283,231	476,423	5.811
12)	Oil Well Gas (MMcf)	593,548	759,179	1,163,762	1.163
	Gas Wells:				
13)	Condensate (000 Bbls)	12,103	16,022	35,473	5.811
14)	Gas Well Gas (MMcf)	1,090,299	1,232,551	2,379,385	1.092
	Royalties Received:				
15)	Liquids (000 Bbls)	25,069	24,899	29,101	2/
16)	Gas (MMcf)	171,863	212,314	221,430	2/

1/ Millions of Btu's per Mcf or per Barrel.
2/ Unit Btu's for royalty volumes are the weighted average for all liquids or all gas, computed for each year.
3/ Volumes @ 14.65 psia.
4/ Volumes @ 14.73 psia.

Exhibit No. 51

[10,188]

Schedule 3
Sheet 2 of 3

SOURCE:

COLUMN A

Lines 1-10, 13-16:

Docket No. AR61-2, Exhibit 115, Part E.

Lines 1, 3, 5, 7, 9—Sum of line 32 of Schedule 8 and line 9 of Schedule 9.

Lines 2, 4, 6, 8, 10—Sum of line 33 of Schedule 8 and line 10 of Schedule 9.

Line 13—Sum of line 32, Col. (G) of Schedule 8 and line 9, Col. (G) of Schedule 9 less Exhibit 51, Schedule 3, Sheet 1, line 11.

Line 14—Sum of line 33, Col. (G) of Schedule 8 and line 10, Col. (G) of Schedule 9 less Exhibit 51, Schedule 3, Sheet 1 line 12.

Line 15—Schedule 11.

Line 16—Schedule 11.

Lines 12-13:

Docket No. AR61-2, Sum of Exhibit 47 (DWA-1), Schedule K and Exhibit 48 (DWA-2), Schedule K.

Line 12—Item II(A).

Line 13—Item II(C).

Exhibit No. 51

[10,189]

Schedule 3
Sheet 3 of 3

COLUMN B

Area Rate Proceedings, Docket Nos. AR64-1 and AR64-2. Sum of Exhibit —J (R.C.F.-7) and Exhibit —J (R.C.F.-10).

Lines 1, 11—Schedule 5, line 3, Cols. (c) and (h).

Line 3—Schedule 5, line 6, Col. (d).

Line 5—Schedule 5, line 6, Col. (e).

Lines 7, 9, 13—Schedule 5, line 4, Cols. (f), (g), and (h).

Lines 2, 4, 12—Schedule 5, line 9, Cols. (c), (d), and (h).

Line 6—Schedule 5, line 10, Col. (e).

Lines 8, 10, 14—Schedule 5. Sum of lines 10 and 11, Col. (f).

Line 15—Schedule 11, line 9.

Line 16—Schedule 11, line 10.

COLUMN C

1969 Questionnaire Data, Composite of Independent Producers and Pipeline Affiliates and Natural Gas Pipeline Companies, Packet D, Schedule 5.

Lines 1, 3, 11—Line 1

Lines 5, 7, 9, 13—Line 2

Exhibit No. 51

[Schedule 3, Sheet 3 of 3—Continued]

Lines 2, 4, 12—Line 4

Lines 6, 8, 10, 14—Line 5

Line 15—Line 15

Line 16—Line 16

COLUMN D

Lines 1, 2, 3, 4, 6, 7, 8, 10, 11, 12, 13, and 14 from Area Rate Proceedings, Docket No. AR 69-1, Tr. 743.

Lines 5 and 9 from 40 FPC 698-9, Col. (4).

Exhibit No. 51

[10,190]

Exhibit 51
Schedule 4
Sheet 1 of 3

CONTINENTAL UNITED STATES
Derivation of Adjusted Production Volumes
For Allocation Of
Exploration and Development Costs

		1969 VOLUMES (MMcf) 1/ (A)	ADJUSTMENT FACTOR (B)	1969 ADJUSTED VOLUMES (MMcf) (C)
	Volumes:			
(1)	Oil Only-Crude Oil - 000 Bbls.	279,490	.613	171,327
(2)	Oil Well Gas - MMcf	12,029	.607	7,302
(3)	Oil Casinghead - Crude Oil - 000 Bbls	1,038,947	.613	636,875
(4)	Oil Well Gas - MMcf	1,713,213	.607	1,039,920
(5)	Gas Only-Condensate-000 Bbls.	0	.584	0
(6)	Gas Well Gas MMcf	1,768,378	.579	1,023,891
	Gas Condensate:			
(7)	Lse Sep-Condensate-000 Bbls.	89,106	.584	52,038
(8)	Gas Well Gas - MMcf	5,391,091	.579	3,121,442
(9)	No Lse-Condensate-000 Bbls.	0	.584	0
(10)	Gas Well Gas - MMcf	712,655	.579	412,627
	Combination			
(11)	Oil-Crude Oil-000 Bbls.	476,423	.613	292,047
(12)	Oil Well Gas - MMcf	1,163,762	.607	706,404
(13)	Gas-Condensate-000 Bbls.	35,473	.584	20,716
(14)	Gas Well Gas - MMcf	2,379,385	.579	1,377,664
	Royalties Received			
(15)	Liquids - 000 Bbls.	29,101	.613	17,839
(16)	Gas - MMcf	221,430	.579	128,208

1/ Volumes @ 14.73 psia

Col. (A) - Schedule 3, Sheet 1, Col. (C).
Col. (B) - Schedule 4, Sheet 3, Line 12.
Col. (C) - Col. (A) times Col. (B).

CONTINENTAL UNITED STATES
Findings of Natural Gas, Natural Gas Liquids, and Crude Oil
Per Successful Oil and Gas Well Footage Drilled
1947 - 1961

	Year	Gas-Well Footage (000 Feet) (A)	Oil-Well Footage (000 Feet) (B)	Non-Associated Natural Gas Findings (MM Mcf @ 14.65) (C)	Natural Gas Liquids Findings (000 Mbls) (D)	Crude Oil Findings (000 Mbls) (E)	Associated Natural Gas Findings (MM Mcf @ 14.65) (F)
(1)	1947	13,169	62,802	6,463	251,538	2,464,570	4,518
(2)	1948	12,312	77,307	7,495	470,557	3,795,207	6,413
(3)	1949	12,438	79,428	6,846	386,776	3,187,845	5,829
(4)	1950	13,685	92,695	9,065	766,062	2,562,685	2,985
(5)	1951	13,946	95,106	8,470	723,991	4,413,954	7,583
(6)	1952	15,257	98,147	9,621	556,838	2,749,288	4,725
(7)	1953	18,248	102,135	15,368	743,969	3,296,130	5,005
(8)	1954	18,857	113,362	8,632	107,350	2,873,037	2,967
(9)	1955	19,930	121,149	12,747	514,508	2,870,726	9,271
(10)	1956	22,738	120,351	15,305	609,820	2,974,336	9,546
(11)	1957	23,836	110,043	16,207	137,392	2,424,000	3,910
(12)	1958	25,556	93,105	17,389	858,206	2,608,242	1,611
(13)	1959	26,607	94,610	15,138	703,444	3,666,765	8,396
(14)	1960	28,199	86,568	11,553	725,130	2,365,328	2,417
(15)	1961	29,179	85,508	15,148	694,686	2,657,567	2,113
(16)	1947-1961 Total	293,957	1,432,316	172,437	8,450,267	44,910,488	73,568
(17)	Average Findings Per Foot Drilled			587	29	31	53

SOURCE: Cols. (A) & (B) - Area Rate Proceedings, Docket No. AR61-2. Item H By Reference, Schedule 4 of Exhibit No. 224.
Col. (C) - Total Material Gas Findings as Reported by AGA less Col. (A).
Col. (D) - World Oil, Annual Forecast and Review Issues.
Col. (E) - Reserves of Crude Oil, Natural Gas Liquids, and Natural Gas in the U.S. and Canada, AGA, API & CPA, Vol. 24, May 1970; Table X, pg. 128.
Col. (F) - Reserves of Crude Oil, Natural Gas Liquids, and Natural Gas in the U.S. and Canada, AGA, API and CPA, Vol. 24, May 1970, Table XI, Page 28. Sum of Col. (3), (4), (5) and (6).
Line 16 - Sum of Lines 1-15.
Line 17 - 1947-1961 Total Findings ÷ 1947-1961 Total Footage.

Exhibit 51
Schedule 4
Sheet 2 of 3

CONTINENTAL UNITED STATES
Derivation of Adjustment Factor
for 1969 Production Volumes

		Non-Associated Natural Gas			Associated Natural Gas			Natural Gas Liquids		Crude Oil	
		Successful Gas-Well Footage (000 Ft.) (A)	Calculated Findings (Mcf @ 14.65 psia) (B)	Production (Mcf @ 14.65 psia) (C)	Successful Oil-Well Footage (000 Ft.) (D)	Calculated Findings (Mcf @ 14.65 psia) (E)	Production (Mcf @ 14.65 psia) (F)	Calculated Findings (000 Bbls) (G)	Production (000 Bbls) (H)	Calculated Findings (000 Bbls) (I)	Production (000 Bbls) (J)
(1)	1961	29,292	17,194	9,740	85,636	4,539	3,712	849,468	461,643	2,654,406	2,513,273
(2)	1962	28,950	16,994	10,005	88,432	4,687	3,707	839,550	470,128	2,741,392	2,550,178
(3)	1963	24,533	14,401	10,866	81,809	4,336	3,759	711,457	515,659	2,536,079	2,599,343
(4)	1964	25,597	15,025	11,533	80,463	4,264	3,898	742,313	536,090	2,494,353	2,644,247
(5)	1965	24,931	14,634	13,303	73,322	3,886	4,028	722,999	555,410	2,272,982	2,686,198
(6)	1966	25,636	15,048	13,241	67,430	3,574	4,144	742,444	560,584	2,090,330	2,864,242
(7)	Total		93,296	67,698		29,286	27,402	4,608,231	3,127,630	14,789,542	15,850,481
(8)	Findings/Production Ratio (1961-1966)			1.378			1.070		1.474		0.933
(9)	1969	31,629	12,816	16,059	58,900	3,126	4,777	633,041	735,962	1,826,380	3,195,291
(10)	Imputed 1969 Production			9,299			2,900		429,472		2,759,678
(11)	% Imputed 1969 Production of Actual			57.9			60.7		58.4		61.3

Source: Cols. (A), (B) & (C), lines 1-6 - 40 FPC 562.
Col. (D) lines 1-6 - World Oil, Annual Forecast and Review Issues.
Col. (E), lines 1-6 - Col. (D) times 53 Mcf per foot drilled from line 17 of Col. (C) of Sheet 2 of Schedule 4.
Col. (F), lines 1-6 - Reserves of Crude Oil, Natural Gas Liquids and Natural Gas in the United States and Canada, AGA-API et al; Total Natural Gas Production less Col. (C).
Col. (G), lines 1-6 - Col. (A) times 29 Barrels per foot drilled from line 17 of Col. (E) of Sheet 2 of Schedule 4.
Col. (H), lines 1-6 - Reserves of Crude Oil, Natural Gas Liquids and Natural Gas in the United States and Canada, AGA-API, et al. Table V, p. 128.
Col. (I), lines 1-6 - Col. (D) times 31 Barrels per foot drilled from line 17 of Col. (F) of Sheet 2 of Schedule 4.
Col. (J), lines 1-6 - Reserves of Crude Oil, Natural Gas Liquids and Natural Gas in the United States and Canada, AGA-API, et al. Table II, p. 28.
Line 7 - Sum of Lines 1-6.
Line 8 - Line 7, Col. (B) divided by Col. (C); Col. (E) divided by Col. (F); Col. (G) divided by Col. (H), Col. (I) divided by Col. (J).
Line 9 Cols. (A), (C), (D), (F), (H), and (J) - Ibid.
Col. (B) - Col. (A) times 587 Mcf per foot drilled from line 17 of Col. (A) of Sheet 2 of Schedule 4.
Col. (E) - Col. (D) times 53 Mcf per foot drilled from line 17 of Col. (C) of Sheet 2 of Schedule 4.
Col. (G) - Col. (A) times 29 Barrels per foot drilled from line 17 of Col. (E) of Sheet 2 of Schedule 4.
Col. (I) - Col. (D) times 31 Barrels per foot drilled from line 17 of Col. (F) of Sheet 2 of Schedule 4.
Line 10 - Line 9, Col. (B) divided by Line 8 Col. (C). Line 9 Col. (E) divided by Line 8 Col. (F) Line 9 Col. (G) divided by Line 8, Col. (F) and Line 9 Col. (I) divided by Line 8 Col. (J).
Line 11 - Line 10 divided by Line 9.

Exhibit No. 51

[10,193]

Exhibit 51
Schedule 5
Sheet 1 of 2

CONTINENTAL UNITED STATES
Derivation of Adjusted 1969 Exploration Expenses

	Year	Exploration Expenses (A) ($ Million)
(1)	1960	$ 1,475
(2)	1961	1,425
(3)	1962	1,375
(4)	1963	1,425
(5)	1964	1,575
(6)	1965	1,510
(7)	1966	1,575
(8)	1967	1,465
(9)	1968	1,565
(10)	1969	1,675

(11)	Chase Expenses Adjusted for 1960-1969 Growth in Hydrocarbon Production	1,475 1/	X	1.462/	=	2,154
(12)	Respondents Comparable Expenses as Percent of Chase 1969 Actual	879 3/	+	1,675 4/	=	52%
(13)	Respondents Comparable Expenses of Adjusted Chase	2,154	X	.52	=	1,120
(14)	Respondents Other Expenses Not Included in Line 12					572 5/
(15)	Total Adjusted Expenses	1,120	+	572	=	1,692

SOURCES: Col. (A) - Capital Investments of the World Petroleum Industry for Respective Years - Chase Manhattan Bank. The Sum of U.S. Exploration and Development Expenses in the following categories: dry holes, geological and geophysical, and lease rentals.

1/ Exhibit 51, Schedule -, Sheet 1, Line (1), Col. (A).
2/ Exhibit 51, Schedule , Sheet 2, Line (11).
3/ 1969 Questionnaire Data, Composite of Independent Producers and Pipeline Affiliates and Natural Gas Pipeline Companies, Packet D, Schedule 3, Line 20 less lines 15, 16 and 18 of Col. (F).
4/ Exhibit 51, Schedule , Sheet 1, Line (10), Col. (A).
5/ 1969 Questionnaire Data, Composite of Independent Producers and Pipeline Affiliates and Natural Gas Pipeline Companies, Packet D, Schedule 3, Sum of lines 15, 16, 18, 21 and 22.

CONTINENTAL UNITED STATES
Growth in Equivalent Production of All Hydrocarbons
1960-1969

		Crude Oil (A)	Nat Gas Liquids (B)	Natural Gas (C)	Col. (A)x5.8[1] (D)	Col. (B)x5.4[1] (E)	Col. (C)x1.15[1] (F)	Sum of Col. (D), (E), & (F) (G)
		(000 Bbls)		(MMcf)	(of BTU's)			
(1)	1960	2,471,464	431,379	13,019,356	14,334,491	2,329,447	14,972,259	31,636,197
(2)	1961	2,512,273	461,649	13,378,649	14,571,183	2,492,905	15,385,446	32,449,534
(3)	1962	2,550,178	470,128	13,637,973	14,791,032	2,538,691	15,683,669	33,013,392
(4)	1963	2,593,343	515,659	14,546,025	15,041,389	2,784,559	16,727,929	34,553,877
(5)	1964	2,644,247	536,090	15,347,028	15,336,633	2,894,886	17,649,082	35,880,601
(6)	1965	2,686,198	555,410	16,252,293	15,579,948	2,999,214	18,690,137	37,269,299
(7)	1966	2,864,242	588,684	17,491,073	16,612,604	3,178,894	20,114,734	39,906,232
(8)	1967	3,037,579	644,493	18,380,838	17,617,958	3,480,262	21,137,964	42,236,184
(9)	1968	3,124,188	701,782	19,373,428	18,120,290	3,789,623	22,279,442	44,189,355
(10)	1969	3,195,291	735,962	20,723,190	18,532,688	3,974,195	23,831,668	46,338,551
(11)		GROWTH: $\frac{46,338,551}{31,636,197} = 1.46$						

SOURCE: Cols. (A), (B) and (C), Lines 1-10 RESERVES OF CRUDE OIL, NATURAL GAS LIQUIDS, AND NATURAL GAS IN THE UNITED STATES AND CANADA AND UNITED STATES PRODUCTIVE CAPACITY AS OF DECEMBER 31, 1969. Vol. 24; MAY, 1970

Line 11 - Line 10 of Col. (G) divided by Line 1 of Col. (G).

1/Estimated unit Btu's from Col. (D) of Schedule 3, Sheet 1 of 3.

Exhibit 51
Schedule 3
Sheet 2 of 2

[10,194]

Exhibit No. 52

[10,195]

EXHIBIT No. 52

Witness: Charles A. Larson

UNITED STATES OF AMERICA
FEDERAL POWER COMMISSION

Docket Nos. AR61-2 and AR69-1

IN THE MATTER OF

AREA RATE PROCEEDING, *et al.*:
SOUTHERN LOUISIANA AREA

Summary of Exploration and Development Costs 1960, 1962 and 1969

COMMONWEALTH
SERVICES • INC.

Exhibit No. 52

[10,196]

Exhibit 52

CONTINENTAL UNITED STATES
Exploration Cost Employing Various Economic Factors
1960, 1962 and 1969

	Economic Factor	Unit Cost 1/ (Cents per Mcf)				
				1969		
		1960 (A)	1962 (B)	Actual Costs (C)	Adjusted Costs (D)	Adjusted Volumes (E)
(1)	3.5	4.3¢	4.2¢	3.7¢	4.2¢	6.2¢
(2)	2.92	4.9	4.8	4.2	4.8	7.0
(3)	2.34	5.7	5.6	4.9	5.6	8.2
(4)	2	6.3	6.2	5.4	6.1	9.0
(5)	1	9.4	8.9	7.8	8.8	13.0

1/ At 15.025 psia.

SOURCE: Derived from basic data shown in Exhibit 51.

Exhibit No. 53

[10,197]

EXHIBIT No. 53

Witness: Charles A. Larson

UNITED STATES OF AMERICA
FEDERAL POWER COMMISSION

Docket Nos. AR61-2 and AR69-1

IN THE MATTER OF

AREA RATE PROCEEDING, *et al.*:
SOUTHERN LOUISIANA AREA

SOUTHERN LOUISIANA AREA
Basic Data for the
Production Cost Function
1960, 1962 and 1969

COMMONWEALTH
SERVICES • INC.

SOUTHERN LOUISIANA AREA

Inputs for Production Cost of Service
1960, 1962 and 1969

		Lease Class					
					Gas condensate		
		Oil Only	Oil Casinghead	Gas Only	Lease Separation	No Lease Separation	Combination
		($000)					
	1960	(A)	(B)	(C)	(D)	(E)	(F)
(1)	Expense	$25,623	$ 59,597	$ 1,838	$ 45,628	$ 1,834	$ 74,723
(2)	DD & A	$28,451	$ 46,831	$ 4,836	$ 55,925	$ 1,869	$ 60,599
(3)	Return @ 12%	$42,026	$ 64,115	$ 5,463	$ 102.700	$ 3,006	$ 121,073
(4)	Volumes 1/ - Liquids (000 Mbls)	23,314	96,765	13	29,012	165	112,702
(5)	- Gas (MMcf)	5,427	161,605	10,930	1,274,408	80,398	368,928
(6)	Volumes Re-Injected & Lease Use (MMcf)	5,253	19,095	58	83,259	19,457	23,414
	1962						
(7)	Expense	$12,722	$ 67,594	$ 1,120	$ 56,716	$ 1,892	$ 92,266
(8)	DD & A	$14,638	$ 57,257	$ 1,722	$ 71,825	$ 1,338	$ 81,155
(9)	Return @ 12%	$21,085	$ 93,210	$ 6,548	$ 146,969	$ 2,476	$ 157,504
(10)	Volumes 1/ - Liquids (000 Mbls)	10,864	115,856	-	34,023	-	154,408
(11)	- Gas (MMcf)	957	184,745	13,793	1,523,356	53,965	475,236
(12)	Volumes Re-Injected & Lease Use (MMcf)	957	27,975	264	101,881	20,813	32,078
	1969						
(13)	Expense	$16,154	$129,732	$ 4,096	$ 87,677	$ 6,737	$ 215,519
(14)	DD & A	$16,891	$127,789	$16,038	$ 136,326	$ 7,988	$ 238,564
(15)	Return @ 13%	$23,561	$162,720	$23,123	$ 162,247	27,563	319,760
(16)	Volumes 2/ - Liquids (000 Mbls)	17,489	222,034	-	57,138	-	323,738
(17)	- Gas (MMcf)	5,297	340,162	99,317	2,931,871	108,776	1,453,040
(18)	Volumes Re-Injected & Lease Use (MMcf)	NA	NA	NA	NA	NA	NA

Exhibit 53
Schedule 1
Sheet 1 of 3

1/ Volumes @ 14.65 psia.

2/ Volumes @ 14.73 psia.

[10,199]

Exhibit No. 53

[10,199]

Schedule 1
Sheet 2 of 3

SOURCE:

Line 1 Docket No. AR61-2, Exhibit 115, Part E. Line 1 equals the sum of lines 1, 3 and allocated line 10 of Schedule 12 plus lines 1 and 3 of Schedule 13 for each lease class. (Line 10 of Schedule 12 allocated to lease classes based on the ratio of line 1 plus line 3 for each lease class, to total of line 1 plus line 3 for all lease classes, of Sehedule 12 plus Schedule 13).

Line 2 Docket No. AR61-2, Exhibit 115, Part E Sum of line 2 of Schedule 12 and line 2 of Schedule 13 for each lease class.

Line 3 Schedule 2, Sheet 1 of 3. Line 5 of each lease class multiplied by 12 percent.

Line 4 Docket No. AR61-2, Exhibit 115, Part E Sum of line 28 of Schedule 12 and line 9 of Schedule 13, for each lease class.

Line 5 Docket No. AR61-2, Exhibit 115, Part E. Sum of line 29 of Schedule 12 and line 10 of Schedule 13, for each lease class.

Line 6 Docket No. AR61-2, Exhibit No. 47(DWA-1), Schedule K. Sum of Item III (C) (3) & (4) & Item IV (A), for each lease class.

Line 7 1962 All Areas Questionnaire responses for Southern Louisiana Area, composite of Independent Producers and Affiliated Pipelines, and Natural Gas Pipelines. Schedule G, Sheet 02, Sum of lines 4, 12, 13, 14, and 15. Less Schedule H, Sheet 03, Line 8.

Exhibit No. 53

[Schedule 1, Sheet 2 of 3—Continued]

SOURCE:

Line 8 1962 All Areas Questionnaire responses for Southern Louisiana Area, composite of Independent Producers and Affiliated Pipelines, and Natural Gas Pipelines Schedule G, Sheet 02, line 11.

Line 9 Schedule 2, Sheet 1 of 3. Line 10 of each lease class multiplied by 12 percent.

Line 10 1962 All Areas Questionnaire responses for Southern Louisiana Area, composite of Independent Producers and Affiliated Pipelines, and Natural Gas Pipelines. Schedule H, Sheet 03, line 3.

[10,200]

Schedule 1
Sheet 3 of 3

Line 11 1962 All Areas Questionnaire responses for Southern Louisiana Area, composite of Independent Producers and Affiliated Pipelines, and Natural Gas Pipelines. Schedule H, Sheet 03, line 7.

Line 12 1962 All Area Questionnaire responses for Southern Louisiana Area, composite of Independent Producers and Affiliated Pipelines, and Natural Gas Pipelines. Schedule H, Sheet 03; Sum of lines 10, 11, 12 and 16.

Line 13 1969 Questionnaire Data, Southern Louisiana Area Producers and Pipeline Affiliates, and Natural Gas Pipelines. Packet D, Schedule 5, sum of lines 12, 13, 14, 15, 24, 25 and 26 Less Packet D, Schedule 4, Line 14.

Exhibit No. 53

[Schedule 1, Sheet 3 of 3—Continued]

SOURCE:

Line 14 1969 Questionnaire Data, Southern Louisiana Area (including Federal Domain), composite of Independent Producers and Pipeline Affiliates, and Natural Gas Pipelines Packet D, Schedule 5, sum of lines 16, 17 and 18.

Line 15 Schedule 2, Sheet 1 of 3, Line 15 of each lease class multiplied by 13 percent.

Line 16 1969 Questionnaire Data, Southern Louisiana Area (including Federal Domain), composite of Independent Producers and Pipeline Affiliates, and Natural Gas Pipelines. Packet D, Schedule 4, line 3.

Line 17 1969 Questionnaire Data, Southern Louisiana Area (including Federal Domain), composite of Independent Producers and Pipeline Affiliates, and Natural Gas Pipelines Packet D, Schedule 4, line 6.

SOUTHERN LOUISIANA AREA

Production Rate Base

		Lease Class					
		Oil Only	Oil Casinghead	Gas Only	Gas Condensate Lease Sep	Gas Condensate No Lse Sep	Combination
	1960	($000)					
		(A)	(B)	(C)	(D)	(E)	(F)
(1)	Net Investment	$340,203	$ 516,496	$ 44,408	$ 833,440	$ 24,331	$ 979,983
(2)	Materials & Supplies	6,314	9,588	824	15,470	452	18,190
(3)	Prepayments	497	755	65	1,218	36	1,432
(4)	1/8 Cash Expense	3,203	7,450	230	5,704	228	9,340
(5)	Rate Base	$350,217	$ 534,289	$ 45,527	$ 855,832	$ 25,047	$1,008,945
	1962						
(6)	Net Investment	$171,619	$ 760,621	$ 54,164	$1,205,141	$ 20,218	$1,289,242
(7)	Materials & Supplies	2,310	6,732	242	10,184	156	10,167
(8)	Prepayments	189	987	24	2,275	23	1,560
(9)	1/8 Cash Expense	1,593	8,474	141	7,139	237	11,562
(10)	Rate Base	$175,711	$ 776,814	$ 54,571	$1,224,739	$ 20,634	1,312,831
	1969						
(11)	Net Investment	$178,277	$1,228,980	$176,875	$1,229,340	$210,810	$2,421,249
(12)	Materials & Supplies	774	5,026	416	4,811	297	7,549
(13)	Prepayments	161	1,426	65	2,837	23	3,879
(14)	1/8 Cash Expense	2,024	16,257	515	11,062	891	27,017
(15)	Rate Base	$181,236	$1,25-,689	$177,871	$1,248,050	$212,021	$2,459,694

Exhibit 53
Schedule 2
Sheet 1 of 3

Exhibit No. 53

[10,201]

[10,201]

Exhibit No. 53

[10,202]

Schedule 2
Sheet 2 of 3

SOURCES:

Line 1 Docket No. AR61-2, Exhibit 115, Part E. Sum of lines 15, 19 and 25 of Schedule 12 plus lines 5, 6, 7, 8 of Schedule 13 for each lease class. (Line 25 of Schedule 12 is allocated to lease classes based on the ratio of line 15 plus line 19 of Schedule 12 plus lines 5, 6, 7, and 8 of Schedule 13 for each lease class, to the total of line 15 plus line 19 of Schedule 12 plus lines 5, 6, 7, and 8 of Schedule 13)

Line 2 Docket No. AR61-2, Exhibit 115, Part E, Schedule 12, line 26, for each lease class. (Line 26 of Schedule 12 is allocated to lease classes based on the ratio of line 15 plus line 19 of Schedule 12 plus lines 5, 6, 7, and 8 of Schedule 13 for each lease class, to the total of line 15 plus line 19 of Schedule 12 plus lines 5, 6, 7 and 8 of Schedule 13.)

Line 3 Docket No. AR61-2, Exhibit 115, Part E, Schedule 12, line 27. (Line 27 of Schedule 12 is allocated to lease classes based on the ratio of line 15 plus line 19 of Schedule 12 plus lines 5, 6, 7, 8 of Schedule 13 for each lease class, to the total of line 15 plus line 19 of Schedule 12 plus lines 5, 6, 7, and 8 of Schedule 13.)

Line 4 Exhibit 53, Schedule 1, Sheet 1, Line 1 times 1/8.

Line 5 Sum of Lines 1, 2, 3, and 4.

Exhibit No. 53

[Schedule 2, Sheet 2 of 3—Continued]

SOURCES:

Line 6 1962 All Areas Questionnaire, Southern Louisiana Area (Including Federal Domain), Schedule D, Sheet 02, Sum of Lines, 24, 25, and 26.

Line 7 1962 All Areas Questionnaire, Southern Louisiana Area (Including Federal Domain), Schedule D, Sheet 02, Line 27.

Line 8 1962 All Areas Questionnaire, Southern Louisiana Area (Including Federal Domain), Schedule D, Sheet 02, Line 28.

Line 9 1962 All Areas Questionnaire responses for Southern Louisiana Area, Composite of Independent Producers and Affiliated Pipelines and Natural Gas Pipeline. Schedule G, Sheet 02, Sum of Lines 4, 12, 13, 14 and 15 multiplied by 1/8.

Line 10 Sum of Lines 6, 7, 8 and 9.

[10,203]

Schedule 2
Sheet 3 of 3

Line 11 1969 Questionnaire Data, Packet D, Southern Louisiana Area (Including Federal Domain), Schedule 5. Sum of Lines 2, 4, 6, 8, 11, 19, 20 and 23.

[10,203]

Exhibit No. 53

[Schedule 2, Sheet 3 of 3—Continued]

SOURCES:

Line 12 1969 Questionnaire Data, Packet D, Southern Louisiana Area (Including Federal Domain), Schedule 5, Line 21.

Line 13 1969 Questionnaire Data, Packet D, Southern Louisiana Area (Including Federal Domain), Schedule 5, Line 22.

Line 14 1969 Questionnaire Data, Southern Louisiana Area Producers and Pipeline Affiliates, and Natural Gas Pipelines. Packet D, Schedule 5, sum of Lines 12, 13, 14, 15, 24, 25 and 26 multiplied by 1/8.

Line 15 Sum of Lines 11, 12, 13 and 14.

RELATIVE COST RATIOS

	Modification	1960 (A)	1962 (B)	1969 (C)
(1)	Continental U.S.-Excluding Shut-In Lease Costs, Using Gross Investment and Volumes Produced			
1	Expenses	45.52	42.87	44.00
2	DD & A	22.39	24.87	17.01
3	Return	21.12	17.42	18.75
(2)	Continental U.S.-Excluding Shut-In Lease Costs, Using Gross Investment and Volumes Produced, Excluding Hugoton-Anadarko Area			
4	Expenses	NA	24.19	39.26
5	DD & A	NA	11.17	12.27
6	Return	NA	8.72	14.32
(3)	Continental U.S.-Using Gross Investment and Volumes Produced			
7	Expenses	44.36	42.05	43.31
8	DD & A	21.31	24.42	16.93
9	Return	17.98	15.97	17.91
(4)	Continental U.S.-Excluding Shut-In Well Costs, Using Gross Investment and Volumes Produced			
10	Expenses	NA	NA	43.00
11	DD & A	NA	NA	16.66
12	Return	NA	NA	17.75
(5)	Continental U.S.-Excluding Shut-In Lease Costs, Using Gross Investment and Volumes Produced Less Volumes Re-Injected & Lease Use			
13	Expenses	45.09	42.87	NA
14	DD & A	22.22	24.76	NA
15	Return	20.92	17.37	NA
(6)	Continental U.S.-Excluding Shut-In Lease Costs, Using Net Investment and Volumes Produced			
16	Expenses	45.52	42.87	44.00
17	DD & A	22.39	24.87	17.01
18	Return	14.62	10.96	12.51
(7)	Continental U.S.-Using Net Investment and Volumes Produced			
19	Expenses	44.36	42.05	43.31
20	DD & A	21.31	24.42	16.93
21	Return	11.62	9.65	11.86
(8)	Continental U.S.-Using Net Investment and Volumes Produced, Excluding Hugoton Anadarko Area			
22	Expenses	NA	23.48	38.44
23	DD & A	NA	10.94	12.16
24	Return	NA	4.91	8.76
(9)	Continental U.S.-Using Net Investment and Volumes Produced Less Volumes Re-Injected & Lease Use			
25	Expenses	43.98	42.05	NA
26	DD & A	21.08	24.31	NA
27	Return	11.50	9.65	NA

SOURCE: Schedule 4, Oil Only Col. Divided by Gas Only Col. For Each Year Respectively
Lines 1, 2 and 3 - Sheet 1 of 9
Lines 4, 5 and 6 - Sheet 2 of 9
Lines 7, 8 and 9 - Sheet 3 of 9
Lines 10, 11 and 12 - Sheet 4 of 9
Lines 13, 14 and 15 - Sheet 5 of 9
Lines 16, 17 and 18 - Sheet 6 of 9
Lines 19, 20 and 21 - Sheet 7 of 9
Lines 22, 23 and 24 - Sheet 8 of 9
Lines 25, 26 and 27 - Sheet 9 of 9

Exhibit No. 53 [10,204]

Exhibit 53
Schedule 3

[10,204]

[10,205]

Exhibit No. 53

[10,205]

CONTINENTAL UNITED STATES
Unit Costs for Relative Cost Ratios
Excluding Shut-In Lease Costs, Using Gross Investment and Volumes Produced

	1960		1962		1969	
	Oil Only (A)	Gas Only (B)	Oil Only (C)	Gas Only (D)	Oil Only (E)	Gas Only (F)
	(Dollars per Mcf or per Barrel)					
(1) Expenses	0.965	0.0212	0.776	0.0181	1.034	0.0235
(2) DD & A	0.580	0.0259	0.562	0.0226	0.585	0.0344
(3) Gross Investment	11.173	0.529	12.002	0.689	13.631	0.727

SOURCE: Schedule 5, Sheet 1 of 8 Less Sheet 3 of 8.
Line 1 - Line 1 Divided by Line 5.
Line 2 - Line 2 Divided by Line 5.
Line 3 - Line 3 Divided by Line 5.

For Each Col. and Each Year Respectively

Exhibit 53
Schedule 4
Sheet 1 of 9

CONTINENTAL UNITED STATES
Unit Cost For Relative Cost Ratios
Excluding Shut-In Leases, Using Gross Investment and Volumes Produced
and Excluding Hugoton Anadarko Area

		1960		1962		1969	
		Oil Only (A)	Gas Only (B)	Oil Only (C)	Gas Only (D)	Oil Only (E)	Gas Only (F)
		(Dollars per Mcf or per Barrels)					
(1)	Expense	NA	NA	0.733	.0303	1.0173	0.0259
(2)	DD & A	NA	NA	0.546	0.489	0.5940	0.0484
(3)	Gross Investment	NA	NA	11.643	1.335	13.4627	0.9403

SOURCE: Schedule 6, Sheet 1 of 8 Less Sheet 3 of 8 Less Sheet 5 of 8 plus Sheet 7 of 8.
Line 1 - Line 1 Divided by Line 5.
Line 2 - Line 2 Divided by Line 5.
Line 3 - Line 3 Divided by Line 5.

For Each Col. and Each Year Respectively.

Exhibit No. 53
Schedule 4
Sheet 2 of 9

[10,206]

[10,207]

Exhibit No. 53

[10,207]

CONTINENTAL UNITED STATES
Unit Costs for Relative Cost Ratios
Using Gross Investment and Volumes Produced

		1960		1962		1969	
		Oil Only (A)	Gas Only (B)	Oil Only (C)	Gas Only (D)	Oil Only (E)	Gas Only (F)
		(Dollars per Mcf or per Barrel)					
(1)	Expenses	0.967	0.0218	0.778	0.0185	1.035	0.0239
(2)	DD & A	0.584	0.0274	0.564	0.0231	0.591	0.0349
(3)	Gross Investment	11.344	0.631	12.230	0.766	13.811	0.771

158 e

SOURCE: Schedule 5, Sheet 1 of 8.

Line 1 - Line 1 Divided by Line 5.
Line 2 - Line 2 Divided by Line 5.
Line 3 - Line 3 Divided by Line 5.

For Each Col. and Year Respectively.

Exhibit 53
Schedule 4
Sheet 3 of 9

CONTINENTAL UNITED STATES
Unit Costs For Relative Cost Ratios
Excluding Shut-In Well Costs, Using Gross Investment and Volumes Produced

		1960		1962		1969	
		Oil Only (A)	Gas Only (B)	Oil Only (C)	Gas Only (D)	Oil Only (E)	Gas Only (F)
		(Dollars per Mcf or per Barrel)					
(1)	Expenses	NA	NA	NA	NA	1.002	0.0233
(2)	DD & A	NA	NA	NA	NA	0.568	0.0341
(3)	Gross Investment	NA	NA	NA	NA	12.743	0.718

SOURCE: Schedule 5, Sheet 1 of 8 less Sheet 4 of 8.

Line 1 Line 1 Divided by Line 5.
Line 2 - Line 2 Divided by Line 5.
Line 3 - Line 3 Divided by Line 5.

For Each Col. and Each Year Respectively.

159 e

[10,208]

Exhibit No. 53

[10,208]

Exhibit 53
Schedule 4
Sheet 4 of 9

[10,209]

Exhibit No. 53

[10,209]

CONTINENTAL UNITED STATES
Unit Costs for Relative Cost Ratios
Excluding Shut-In Lease Costs, Using Gross Investment and Volumes Produced
Less Re-Injected Volumes and Lease Use

	1960		1962		1969	
	Oil Only (A)	Gas Only (B)	Oil Only (C)	Gas Only (D)	Oil Only (E)	Gas Only (F)
	(Dollars per Mcf or per Barrel)					
(1) Expenses	0.967	0.0218	0.776	0.0181	1.034	NA
(2) DD & A	0.584	0.0274	0.562	0.0227	0.585	NA
(3) Gross Investment	11.344	0.631	12.002	0.691	13.631	NA

160 e

SOURCE: Schedule 5, Sheet 1 of 8 Less Sheet 3 of 8.

Line 1 - Line 1 Divided by(Line 5 Less Line 6)
Line 2 - Line 2 Divided by (Line 5 Less Line 6)
Line 3 - Line 3 Divided by (Line 5 Less Line 6)

For Each Col. and Each Year Respectively.

Exhibit 53
Schedule 4
Sheet 5 of 9

CONTINENTAL UNITED STATES
Unit Costs For Relative Cost Ratios
Excluding Shut-In Lease Costs, Using Net Investment and Volumes Produced

	1960		1962		1969	
	Oil Only (A)	Gas Only (B)	Oil Only (C)	Gas Only (D)	Oil Only (E)	Gas Only (F)
	(Dollars per Mcf or per Barrel)					
(1) Expenses	0.965	0.0212	0.776	0.0181	1.034	0.0235
(2) DD & A	0.580	0.0259	0.562	0.0226	0.585	0.0344
(3) Net Investment	4.402	0.301	4.459	0.407	5.316	0.425

SOURCE: Schedule 5, Sheet 1 of 8 Less Sheet 3 of 8.

Line 1 - Line 1 Divided by Line 5.
Line 2 - Line 2 Divided by Line 5.
Line 3 - Line 4 Divided by Line 5.

For Each Col. and Each Year Respectively

Exhibit No. 53

Exhibit 53
Schedule 4
Sheet 6 of 9

[10,210]

CONTINENTAL UNITED STATES
Unit Costs for Relative Cost Ratios
Using Net Investment and Volumes Produced

	1960		1962		1969	
	Oil Only (A)	Gas Only (B)	Oil Only (C)	Gas Only (D)	Oil Only (E)	Gas Only (F)
	(Dollars per Mcf or per Barrel)					
(1) Expenses	0.967	0.0218	0.778	0.0185	1.035	0.0239
(2) DD & A	0.584	0.0274	0.564	0.0231	0.591	0.0349
(3) Net Investment	4.544	0.391	4.592	0.476	5.422	0.457

SOURCE: Schedule 5 Sheet 1 of 8

Line 1 - Line 1 Divided by Line 5
Line 2 - Line 2 Divided by Line 5
Line 3 - Line 4 Divided by Line 5

For Each Col. and Each Year Respectively

CONTINENTAL UNITED STATES
Unit Costs for Relative Cost Ratios
Using Net Investment and Volumes Produced, Excluding Hugoton Anadarko Areas

	1960		1962		1969	
	Oil Only (A)	Gas Only (B)	Oil Only (C)	Gas Only (D)	Oil Only (E)	Gas Only (F)
	(Dollars per Mcf or per Barrel)					
(1) Expenses	NA	NA	0.735	0.0313	1.0186	0.0265
(2) DD & A	NA	NA	0.549	0.0502	0.6008	0.0494
(3) Net Investment	NA	NA	4.631	0.943	5.5169	0.6299

SOURCE: Schedule 5, Sheet 1 or 8 Less Sheet 5 of 8

Line 1 - Line 1 Divided by Line 5.
Line 2 - Line 2 Divided by Line 5.
Line 3 - Line 4 Divided by Line 5.

For Each Col. and Each Year Respectively

[10,212]

Exhibit 53
Schedule 4
Sheet 8 of 9

Exhibit No. 53

[10,213]

Exhibit 53
Schedule 4
Sheet 9 of 9

CONTINENTAL UNITED STATES
Unit Costs for Relative Cost Ratios
Using Net Investment and Volumes Produced
Less Re-Injected Volumes and Lease Use

	1960		1962		1969	
	Oil Only (A)	Gas Only (B)	Oil Only (C)	Gas Only (D)	Oil Only (E)	Gas Only (F)
	(Dollars per Mcf or per Barrel)					
(1) Expenses	0.967	0.0220	0.778	0.0185		NA
(2) DD & A	0.584	0.0277	0.564	0.0232		NA
(3) Net Investment	4.544	0.395	4.592	0.476		NA

SOURCE: Schedule 5, Sheet 1 of 8

Line 1 - Line 1 Divided by (Line 5 Less Line 6)
Line 2 - Line 2 Divided by (Line 5 Less Line 6)
Line 3 - Line 4 Divided by (Line 5 Less Line 6)

Exhibit No. 53

Exhibit 53
Schedule 5
Sheet 1 of 8

CONTINENTAL UNITED STATES
Basic Cost Data For Unit Cost Computations for Relative Cost Ratios

		1960		1962		1969	
		Oil Only (A)	Gas Only (B)	Oil Only (C)	Gas Only (D)	Oil Only (E)	Gas Only (F)
		(000 Dollars)					
(1)	Expenses	$ 320,882	$ 17,632	$ 183,424	$ 27,162	$ 289,342	$ 42,221
(2)	DD & A	193,854	22,163	133,047	34,010	165,140	61,783
(3)	Gross Investment	3,765,001	510,225	2,883,266	1,125,795	3,860,170	1,364,279
(4)	Net Investment	1,508,149	316,427	1,082,530	699,216	1,515,487	808,330
(5)	Volumes Produced (000 Bbls & 000Mcf)	331,886	808,390	235,761	1,470,439	279,490	1,768,378
(6)	Volumes Re-Injected & Lease Use (000Mcf)		7,709		2,624		NA

SOURCE: Cols. (A) and (B)

Line 1 - Docket No. AR61-2, Exhibit 144 Schedule 3, Cols. (4) and (5).
Line 8 less Line 10.
Line 2 - Docket No. AR61-2, Exhibit 144 Schedule 3, Cols (6) and (7).
Line 8.
Line 3 - Docket No. AR61-2, Exhibit 144 Schedule 3, Cols. (4) and (5).
Line 23.
Line 4 - Docket No. AR61-2, Exhibit No. 29 Revised, Schedule 3, Sheet 2,
Cols. (4) and (8), Line 10.
Line 5 - Docket No. AR61-2, Exhibit 144 Schedule 3, Col. (4), Line 3
and Col. (5), Line 4.
Line 6 of Col. (B) - Docket AR61-2, Exhibit Nos. 47 and 48, Items III (C), (3)
and IV (A) of Schedule K.

[10,214]

SOURCES con't

Cols. (C) and (D), Lines 1-4 - Docket Nos. AR64-1 and 2, Exhibits 49J and 50J composited.
Line 1 - Schedule No. 1, Sheet 1 of 1, Line 2 of Cols. (d) and (f) in 49J and Line 3 of Cols. (d) and (f) in 50 J.
Line 2 - Schedule No. 1, Sheet 1 of 1, Line 4 of Cols.(d) and (f) in 49J and Line 7 of Cols. (d) and (f) in 50 J.
Line 3 - Schedule No. 4, Sheet 1 of 2, Sum of Lines 19, 23, 27 and 39 of Cols. (d) and (f) in 49J, and Lines 10, 22, 26 and 37, Cols. (d) and (f) in 50J.
Line 4 - Schedule No. 4, Sheet 1 of 2, Line 41 of Cols. (d) and (f), 49J and Line 39, Cols. (d) and (f) in 50J.

Lines 5 and 6 of Cols. (C) and (D) - Docket Nos. AR64-1 and 2, Exhibits and _____ composited.
Line 5 of Col. (C) - Schedule No. 5, Sheet 1 of 1, Line 6 of Col. (c)
Line 5 of Col. (D) - Schedule No. 5, Sheet 1 of 1, Line 13 of (Col. (e).
Line 6 of Col. (D) - Schedule No. 5, Sheet 1 of 1, Sum of Lines 21, 22, 23, 31 and 32 of Col. (e).

Cols. (E) and (F) - 1969 Questionnaire Responses.
Line 1 - Packet D, Schedule 5, Sum of Lines 12, 13, 14 and 15 of Cols. (c) and(e).
Line 2 - Packet D, Schedule 5, Sum of Lines 16, 17, and 18 of Cols. (c) and (e).
Line 3 - Packet D, Schedule 5, Sum of Lines 1, 3, 5, 7, 9 and 11 of Cols. (c) and (e).
Line 4 - Packet D, Schedule 5, Sum of Lines 2, 4, 6, 8, 10 and 11 of Cols. (c) and (e).
Line 5 of Col. E - Packet D, Schedule 4, Line 3 of Col. (c).
Line 5 of Col. F - Packet D, Schedule 4, Line 6 of Col. (e).

CONTINENTAL UNITED STATES
Basic Cost Data For Unit Cost Computations for Relative Cost Ratios
Costs Applicable to Shut-In Leases

		1960		1962		1969	
		Oil Only (A)	Gas Only (B)	Oil Only (C)	Gas Only (D)	Oil Only (E)	Gas Only (F)
		(000 Dollars)					
(1)	Expenses	$ 544	$ 527	$ 553	$ 526	$ 348	$ 637
(2)	DD & A	1,273	1,248	652	751	1,750	1,034
(3)	Gross Investment	56,970	82,808	53,677	112,149	50,307	78,889
(4)	Net Investment	46,936	72,847	31,257	101,250	29,812	57,009

SOURCE: Cols. (A) and (B)
Line 1 - Docket No. AR61-2, Exhibit 144 (AFB-2), Schedule 3, Sheet 1, Line 9, Cols (4) and (5).
Line 2 - Docket No. AR61-2, Exhibit 144 (AFB-2), Schedule 3, Sheet 1, Line 9, Cols. (6) and (7).
Line 3 - Docket No. AR61-2, Exhibit 144 (AFB-2), Schedule 3, Sheet 1, Line 24, Cols. (2) and (3).
Line 4 - Docket No. Ar61-2, Exhibit 29 (JHL-1) Revised, Schedule 7, Line 6, Cols. (4) and (5).

Cols. (C) and (D), Docket Nos. AR 64-1 and 2, Exhibit Nos. 49-J and 50-J composited.
Line 1 - Schedule No. 5, Sheet 1 of 2, Line 10 of Cols. (d) and (f).
Line 2 - Schedule No. 5, Sheet 1 of 2, Line 12 of Cols. (d) and (f).
Line 3 - Schedule No. 5, Sheet 2 of 2, Line 6 of Cols. (d) and (f)
Line 4 - Schedule No. 5, Sheet 1 of 2, Sum of Lines 2, 3, 4 and 5 of (Cols. (d) & (f)

Cols. (E) and (F), 1969 Questionnaire Responses.
Line 1 - Packet D, Schedule 5-1, Sum of Lines 12, 13, 14 and 15.
Line 2 - Packet D, Schedule 5-1, Sum of Lines 16, 17 and 18.
Line 3 - Packet D, Schedule 5-1, Sum of Lines 1, 3, 5, 7, 9 and 11.
Line 4 - Packet D, Schedule 5-1, Sum of Lines 2, 4, 6, 8, 10 and 11.

Exhibit 53
Schedule 5
Sheet 3 of 8

10-21-69

Exhibit No. 53
[10,216]

[10,216]

Exhibit No. 53

[10,217]

Exhibit 53
Schedule 5
Sheet 4 of 8

CONTINENTAL UNITED STATES
Basic Cost Data For Unit Cost Computations For Relative Cost Ratios
Costs Applicable to Shut-In Wells

	1960		1962		1969	
	Oil Only (A)	Gas Only (B)	Oil Only (C)	Gas Only (D)	Oil Only (E)	Gas Only (F)
	(000 Dollars)					
(1) Expenses	NA	NA	NA	NA	$ 9,208	$ 971
(2) DD & A	NA	NA	NA	NA	6,364	1,438
(3) Gross Investment	NA	NA	NA	NA	298,496	93,846
(4) Net Investment	NA	NA	NA	NA	101,442	64,119

SOURCE: Cols. (E) and (F), 1969 Questionnaire Responses
Line 1 - Packet D, Schedule 5-2, Sum of Lines 12, 13, 14 and 15, of Cols. (c) and (e).
Line 2 - Packet D, Schedule 5-2, Sum of Lines 16, 17 and 18, of Cols. (c) and (e).
Line 3 - Packet D, Schedule 5-2, Sum of Lines 1, 3, 5, 7, 9 and 11 of Cols. (c) and (e).
Line 4 - Packet D, Schedule 5-2, Sum of Lines 2, 4, 6, 8, 10 and 11, of Cols. (c) and (e).

HUGOTON-ANADARKO AREAS
Basic Cost Data For Unit Cost Computations For Relative Cost Ratios

	1960		1962		1969	
	Oil Only (A)	Gas Only (B)	Oil Only (C)	Gas Only (D)	Oil Only (E)	Gas Only (F)
	(000 Dollars)					
(1) Expenses	NA	NA	$ 36,991	$ 12,739	$ 27,069	$14,755
(2) DD & A	NA	NA	23,743	10,843	10,440	10,620
(3) Gross Investment	NA	NA	514,762	410,826	343,511	311,407
(4) Net Investment	NA	NA	160,349	264,214	95,019	155,912
(5) Volumes Produced (000 Bbls and 000 Mcf)	NA	NA	36,632	1,009,269	22,012	732,587
(6) Volumes Re-Injected & Lease Use	NA	NA		234		NA

SOURCE: Cols. (C) and (D), Lines 1-4, Docket No. AR 64-1, Exhibits Nos. _____ and _____ composited.
Line 1 - Schedule No. 2, Sheet 1 of 1, Line 6 of Cols. (d) and (f).
Line 2 - Schedule No. 2, Sheet 1 of 1, Cols. (d) and (f), Line 20, Exhibit No._____ and Line 21, Exhibit No. _____.
Line 3 - Schedule No. 4, Sheet 1 of 2, Sum of Lines 2, 5, 8, 11, 17, 20 and 30 of Cols. (d) and (f).
Line 4 - Schedule No. 4, Sheet 1 of 2, Line 31 of Cols. (d) and (f).

Cols. (C) and (D), Lines 5 and 6, Docket No. AR 64-1, Exhibits Nos. _____ and _____ composited.
Line 5 of Col. (C) - Schedule No. 1, Sheet 1 of 1, Line 6 of Col. (c).

Exhibit 53
Schedule 5
Sheet 5 of 8

[10,218]

Exhibit No. 53

[10,219]

Exhibit 53
Schedule 5
Sheet 6 of 8

SOURCE: con't

Line 5 of Col. (D) - Schedule No. 1, Sheet 1 of 1, Col. (e), Line 23, Exhibit No. _____ and Line 12, Exhibit No. _____.

Line 6 of Col. (D) - Schedule No. 1, Sheet 1 of 1, Col. (e), Sum of Lines 21, 22, 23, 31 and 32, Exhibit No. _____ and lines 20, 21, 22, 30 and 31, Exhibit No. _____.

Cols. (E) and (F), 1969 Questionnaire Responses for Composite of FPC Areas 14, 16, 17 and 19.

Line 1 - Packet D, Schedule 5, Sum of Lines 12, 13,14 and 15, Cols. (C) and (e).

Line 2 - Packet D, Schedule 5, Sum of Lines 16, 17, and 18, Cols. (c) and (e).

Line 3 - Packet D, Schedule 5, Sum of Lines 1, 3, 5, 7, 9 and 11, Cols. (c) and (e).

Line 4 - Packet D, Schedule 5, Sum of Lines 2, 4, 6, 8, 10 and 11, Cols. (c) and (e).

Line 5 of Col.(E) - Packet D, Schedule 4, Line 3 of Col. (c).

Line 5 of Col.(F) - Packet D, Schedule 4, Line 6 of Col. (e).

HUGOTON-ANADARKO AREAS
Basic Cost Data for Unit Cost Computations For Relative Cost Ratios
Costs Applicable to Shut-In Leases

	1960		1962		1969	
	Oil Only (A)	Gas Only (B)	Oil Only (C)	Gas Only (D)	Oil Only (E)	Gas Only (F)
	(000 Dollars)					
(1) Expenses	NA	NA	$ 64	$ 89	0	0
(2) DD & A	NA	NA	116	127	0	0
(3) Gross Investment	NA	NA	3,725	12,802	0	0
(4) Net Investment	NA	NA	2,369	11,872	0	0

SOURCE: Cols. (C) and (D) - Docket No. AR64-1, Exhibits Nos. _____ and _____ composited.
Line 1 - Schedule No. 5, Sheet 1 of 2, Line 10 of Cols. (d) and (f).
Line 2 - Schedule No. 5, Sheet 1 of 2, Line 12 of Cols. (d) and (f).
Line 3 - Schedule No. 5, Sheet 2 of 2, Line 12, of Cols. (d) and (f), Line 12, Exhibit No. _____ and Line 6, Exhibit _____.
Line 4 - Schedule No. 5, Sheet 1 of 2, Sum of Lines 1-5, Cols. (d) and (f).

Cols. (E) and (F) - 1969 Questionnaire Responses for Composite of FPC Areas 14, 16, 17 and 19.
Line 1 - Packet D, Schedule 5-1, Sum of Lines 12, 13, 14 and 15.
Line 2 - Packet D, Schedule 5-1, Sum of Lines 16, 17, and 18.
Line 3 - Packet D, Schedule 5-1, Sum of Lines 1, 3, 5, 7, 9 and 11.
Line 4 - Packet D, Schedule 501, Sum of Lines 2, 4, 6, 8, 10 and 11.

Exhibit No. 53

Exhibit 53
Schedule 5
Sheet 7 of 8

[10,220]

HUGOTON-ANADARKO AREAS
Basic Cost Data For Unit Cost Computations For Relative Cost Ratios
Costs Applicable To Shut-In Wells

	1960		1962		1969	
	Oil Only (A)	Gas Only (B)	Oil Only (C)	Gas Only (D)	Oil Only (E)	Gas Only (F)
	(000 Dollars)					
(1) Expenses	NA	NA	NA	NA	0	0
(2) DD & A	NA	NA	NA	NA	0	0
(3) Gross Investment	NA	NA	NA	NA	0	0
(4) Net Investment	NA	NA	NA	NA	0	0

SOURCE: Cols. (E) and (F) - 1969 Questionnaire Responses for Composite of FPC Areas 14, 16, 17 and 19.

Line 1 - Packet D, Schedule 5-2, Sum of Lines 12, 13, 14 and 15.
Line 2 - Packet D, Schedule 5-2, Sum of Lines 16, 17 and 18.
Line 3 - Packet D, Schedule 5-2, Sum of Lines 1, 3, 5, 7, 9 and 11.
Line 4 - Packet D, Schedule 5-2, Sum of Lines 2, 4, 6, 8, 10 and 11.

Exhibit 53 / Schedule 5 Sheet 8 of 8

Exhibit No. 54

[10,222]

EXHIBIT No. 54

Witness: Charles A. Larson

UNITED STATES OF AMERICA
FEDERAL POWER COMMISSION

Docket Nos. AR61-2 and AR69-1

IN THE MATTER OF

AREA RATE PROCEEDING, *et al.*:
SOUTHERN LOUISIANA AREA

Summary of Production Costs
1960, 1962 and 1969

COMMONWEALTH
SERVICES • INC.

[10,223]

Exhibit No. 54

[10,223]

Exhibit 54

SOUTHERN LOUISIANA AREA
Production Cost
Employing Various Relative Cost Ratios
1960, 1962 and 1969

	Modification	Unit Cost 1/ (Cents per Mcf) 1960 (A)	1962 (B)	1969 (C)
(1)	Opinion No. 546	11.0¢	12.6¢	11.5¢
(2)	Excluding Hogoton from Legs	NA	15.0	12.1
(3)	Including Shut-In Leases in Legs	11.4	12.8	11.6
(4)	Excluding Shut-In Wells	NA	NA	11.6
(5)	Using Net Production Volumes	11.7	13.4	NA
(6)	Using Net Investment Legs	11.6	13.4	11.9
(7)	Modifications on Lines 3 and 6	12.0	13.6	11.9
(8)	Modifications on Lines 2, 3 and 6	NA	15.6	12.5
(9)	Modifications on Lines 3, 5 and 6	12.8	14.5	NA
(10)	Using an Economic Factor of 3.5	12.4	13.7	12.1
(11)	Using an Economic Factor of 2.34	13.5	15.1	13.0
(12)	Using an Economic Factor of 1	15.2	16.9	14.2

1/ At 15.025 psia.

SOURCE: Derived by computer from basic data and relative cost ratios for various modifications shown in Exhibit 53.

Exhibit No. 56

[10,231]

EXHIBIT No. 56

Witness: Charles A. Larson

UNITED STATES OF AMERICA
FEDERAL POWER COMMISSION

Docket Nos. AR61-2 and AR69-1

IN THE MATTER OF

AREA RATE PROCEEDING, *et al.*:
SOUTHERN LOUISIANA AREA

Summary of Unit Cost of Flowing Gas-Well Gas
1960, 1962 and 1969

COMMONWEALTH
SERVICES • INC.

Exhibit No. 56

[10,232]

Exhibit 56

SOUTHERN LOUISIANA AREA
Cost of Gas
1960, 1962 and 1969

		Unit Cost of Flowing Gas Well Gas 1/ (Cents per Mcf)		
	Opinion 546:	1960 (A)	1962 (B)	1969 (C)
(1)	Exploration Cost 2/	4.3¢	4.2¢	6.2¢
(2)	Production Cost 3/	11.0	12.6	11.5
(3)	Gathering Cost	.5	.5	.5
(4)	Regulatory Expense	.2	.2	.2
(5)	Production Taxes	2.3	2.3	2.3
(6)	Total Cost	18.3¢	19.8¢	20.7¢
	Using an Economic Factor of 2.34:			
(7)	Exploration Cost 2/	5.7¢	5.6¢	8.2¢
(8)	Production Cost 3/	13.5	15.1	13.0
(9)	Gathering Cost	.5	.5	.5
(10)	Regulatory Expense	.2	.2	.2
(11)	Production Taxes	2.3	2.3	2.3
(12)	Total Cost	22.2¢	23.7¢	24.2¢
	Using an economic Factor of 1:			
(13)	Exploration Cost 2/	9.4¢	8.9¢	13.0¢
(14)	Production Cost 3/	15.2	16.9	14.2
(15)	Gathering Cost	.5	.5	.5
(16)	Regulatory Expense	.2	.2	.2
(17)	Production Taxes	2.3	2.3	2.3
(18)	Total Cost	27.6¢	28.8¢	30.2¢

1/ At 15.025 psia.
2/ Exhibit 52, Cols. (A), (B), and (E) for appropriate Economic Factor.
3/ Exhibit 54, Cols. (A), (B), and (C) for appropriate Economic Factor.

Exhibit No. 57

[10,233]

EXHIBIT No. 57 (WJO-1)

Witness: William J. Ogden

UNITED STATES OF AMERICA
FEDERAL POWER COMMISSION

Docket Nos. AR61-2 and AR69-1

IN THE MATTER OF

AREA RATE PROCEEDING, *et al.*:
SOUTHERN LOUISIANA AREA

Estimate of the Current Cost of New Gas-Well Gas Per Opinion Nos. 468 and 546

January 1971

COMMONWEALTH
SERVICES • INC.

Exhibit No. 57

[10,234]

Exhibit 57 (WJO-1)
Schedule 1

SUMMARY OF NEW GAS WELL GAS COSTS
PER OPINIONS 468 AND 546

		Unit Cost (¢/Mcf)
1	Successful Well Costs	4.43¢
2	Lease Acquisition Costs	1.68
3	Other Investment Costs	0.52
4	Dry Hole Costs	2.15
5	Other Exploration Costs	1.97
6	Adjustment for Exploration in Excess of Production	1.52
7	Production Expense	2.95
8	Net Liquid Credit	(4.65)
9	Return on Investment [1]	9.48
10	Return on Working Capital [1]	0.57
11	Subtotal @ 14.65 psia	20.62¢
12	Subtotal @ 15.025 psia	21.15¢
13	Regulatory Expense	0.15
14	Royalty @ 14 percent [2]	3.47
15	Area Gathering	0.51
16	Production Tax	2.30
17	Total	27.58¢

SOURCE: Schedule 2.

[1] Return computed at 13 percent.

[2] Royalty in the Southern Louisiana Offshore Federal Domain is a minimum of 16.7 percent.

Exhibit No. 57

[10,235]

Schedule 2
Sheet 1 of 4

DERIVATION OF SCHEDULE 1

SUCCESSFUL WELL COSTS

1 $15.76 \times 1.6482 = \$25.98$ per foot
2 $25.98 \div 587 = 4.43$ ¢/Mcf

LEASE ACQUISITION COSTS

3 $4.43 \times 0.38 = 1.68$ ¢/Mcf

OTHER INVESTMENT COSTS

4 $6.11 \times 0.085 = 0.52$ ¢/Mcf

DRY HOLE COSTS

5 $8.69 \times 1.4921 = \$12.97$ per foot
6 $12.97 \times 1.0828 = \$14.04$ per foot
7 $14.04 \div 654 = 2.15$ ¢/Mcf

SOURCE:

Line 1—15.76—Schedule 3, Sheet 1, Line 5 of Col. (2).
1.6482—Schedule 3, Sheet 2, Line 7 of Col. (1) divided by Schedule 3, Sheet 2, Line 1 of Col. (1).
Line 2—25.98—Line 1 above.
587—40 FPC 567.
Line 3—4.43—Line 2 above.
0.38—Schedule 4, Sheet 1, Line 13.
Line 4—6.11—Sum of Lines 2 and 3 above.
0.085—34 FPC 198

[10,235]

Exhibit No. 57

[Schedule 2, Sheet 1 of 4—Continued]

Line 5—8.69—Schedule 3, Sheet 1, Line 5 of Col. (3)
1.4921—Schedule 3, Sheet 2, Line 7 of Col. (3) divided by Schedule 3, Sheet 2, Line 1 of Col. (3).
Line 6—12.97—Line 5 above.
1.0828—34 FPC 291-292.
Line 7—14.04—Line 6 above.
654—40 FPC 567

[10,236]

Schedule 2
Sheet 2 of 4

OTHER EXPLORATORY COSTS

1 $1.68 \times .68 = 1.14$ ¢/Mcf
2 $9.92 \times .084 = 0.83$ ¢/Mcf
3 $1.14 \times 0.83 = 1.97$ ¢/Mcf

ADJUSTMENT FOR EXPLORATION IN EXCESS OF PRODUCTION

4 $4.12 \times 0.37 = 1.52$ ¢/Mcf

PRODUCTION EXPENSE

5 2.95 ¢/Mcf

NET LIQUID CREDIT

6 4.65 ¢/Mcf

RETURN ON INVESTMENT

7 $6.63 \times 11 \times 0.13 = 9.48$ ¢/Mcf

Exhibit No. 57

[Schedule 2, Sheet 2 of 4—Continued]

SOURCE:

Line 1—1.68—Schedule 2, Sheet 1, Line 3
.68—Schedule 5, Line 7
Line 2—9.92—Sum of Lines 2, 3, 4 & 8 of Schedule 2, Sheet 1 and Line 1 above.
0.084—34 FPC 193
Line 3—1.14—Line 1 above
0.83—Line 2 above
Line 4—4.12—Sum of Line 7 of Schedule 2, Sheet 1 and Line 3 above
0.37—40 FPC 563
Line 5—2.95—Schedule 6, Line 5
Line 6—4.65—Schedule 7, Line 10
Line 7—6.63—Sum of Lines 2, 3 & 4, Schedule 2, Sheet 1
11—40 FPC 580
0.13—Staff Recommended 13% Rate of Return

[10,237]

Schedule 2
Sheet 3 of 4

RETURN ON WORKING CAPITAL

1	5.64 × 1/8=0.70 ¢/Mcf
2	0.70 × 0.39=0.27 ¢/Mcf
3	2.95 × 1/8=0.37 ¢/Mcf
4	0.37 × 1.52=0.56 ¢/Mcf
5	1.68 × 1.5=2.52 ¢/Mcf
6	4.42 × 0.13=0.57 ¢/Mcf

SUBTOTAL @ 14.65 PSIA

7	20.62 ¢/Mcf

[10,237]

Exhibit No. 57

[Schedule 2, Sheet 3 of 4—Continued]

SOURCE:

Line 1—5.64—Sum of Line 7, Schedule 2, Sheet 1 and Lines 3 and 4, Schedule 2, Sheet 2
1/8—30 FPC 204
Line 2—0.70—Line 1 above
0.39—Docket No. AR61-2, Item H, Schedule 12, Line 10.
Line 3—2.95—Schedule 6, Line 5.
1/8—30 FPC 204
Line 4—0.37—Line 3 above.
1.52—Docket No. AR61-2, Item H, Schedule 11, Line 11.
Line 5—1.68—Schedule 2, Sheet 1, Line 3
1.5—40 FPC 511
Line 6—4.42—Sum of Lines 1, 2, 3, 4 and 5 of Schedule 2, Sheet 3.
0.13—Staff Recommended 13% Rate of Return.
Line 7—20.62—Schedule 1, Sum of Lines 1 through 10.

[10,238]

Schedule 2
Sheet 4 of 4

SUBTOTAL @ 15.025 PSIA

1 $20.62 \times 1.0256 = 21.15$ ¢/Mcf

REGULATORY EXPENSE

2 0.15 ¢/Mcf

ROYALTY

3 $21.30 \div 0.86 = 24.74$ ¢/Mcf
4 $24.74 - 21.30 = 3.47$ ¢/Mcf

Exhibit No. 57

[Schedule 2, Sheet 4 of 4—Continued]

AREA GATHERING

5 0.51 ¢/Mcf

PRODUCTION TAX

6 2.30 ¢/Mcf

TOTAL

7 27.58 ¢/Mcf

SOURCE:

Line 1—20.62—Schedule 2, Sheet 3, Line 7.
1.0256—15.025 divided by 14.65.
Line 2—0.15—40 FPC 587
Line 3—21.30—Sum of Lines 1 and 2 above.
0.86—40 FPC 587.
Line 4—24.74—Line 3 above.
21.30—Sum of Lines 1 and 2 above.
Line 5—0.51—40 FPC 589.
Line 6—2.30—40 FPC 586.
Line 7—27.58—Schedule 1, Sum of Lines 12 through 16.

Exhibit No. 57

[10,239]

Exhibit____(MJO-1)
Schedule 3
Sheet 1 of 2

1963 CENSUS DRILLING COSTS

		Oil Wells (1)	Gas Wells (2)	Dry Holes (3)
1	Costs of Drilling and Equipping Wells - (000 $)	$1,048,969	$416,062	$599,608
2	Costs of Lease Equipment Beyond the Christmas Tree Included Above - (000 $)	104,949	18,380	0
3	Wellhead Costs - (000 $)	944,020	397,682	599,608
4	Footage Drilled - (000 Ft.)	80,410	25,241	69,004
5	Cost per Foot of Wellhead Costs - ($/Ft)	11.74	15.76	8.69

SOURCE: Lines 1, 2, and 4 - 1963 Census of Mineral Industries, 1 Summary and Industry Statistics, P. 13B-67.

Line 3 - Line 1 Minus Line 2.

Line 5 - Line 3 Divided by Line 4.

Exhibit No. 57

[10,240]

Exhibit _____ (WJO-1)
Schedule 3
Sheet 2 of 2

DRILLING COSTS REPORTED BY
QUESTIONNAIRE RESPONDENTS

Line	Year	Gas Wells (1)	Oil Wells (2)	Dry Holes (3)
		(Dollars Per Ft)		
1	1963	22.91	15.58	15.81
2	1964	23.62	15.92	16.14
3	1965	24.30	18.15	17.00
4	1966	27.36	18.64	20.05
5	1967	30.73	20.85	21.84
6	1968	32.60	22.34	22.37
7	1969	37.76	23.49	23.59

SOURCE: Col. (1) - Exhibit _____ (CSG-3), Schedule 2, Sheet 1 of 5, Col. (C) for Total Wells.
Col. (2) - Exhibit _____ (CSG-3), Schedule 2, Sheet 2 of 5, Col. (C) for Total Wells.
Col. (3) - Exhibit _____ (CSG-3), Schedule 2, Sheet 3 of 5, Col. (C) for Total Wells.

Exhibit No. 57

[10,241]

Exhibit 57 (WJO-1)
Schedule 4
Sheet 1 of 2

LEASE ACQUISITION COSTS AS PERCENT
OF SUCCESSFUL WELL DRILLING COSTS

Line	Year	Successful Well Drilling Costs (1)	Lease Acquisition Costs (2)
		(Millions of Dollars)	
1	1959	2,409	500
2	1960	2,266	600
3	1961	2,277	400
4	1962	2,317	850
5	1963	2,085	575
6	1964	2,089	650
7	1965	1,946	500
8	1966	1,860	560
9	1967	1,616	860
10	1968	1,574	1,675
11	1969	1,611	1,250
12	1959-1969 Total	22,050	8,420
13	Lease Acquisition Costs as Percent of Successful Well Drilling Costs, 1959-1969 = 38%		

SOURCE: Col. (1) - Schedule 4, Sheet 2 of 2, Col. (5).

Col. (2) - Capital Investments of the World Petroleum Industry, the Chase Manhattan Bank.

Line 13 - Line 12 of Col. (2) Divided By Line 12 of Col. (1).

Exhibit No. 57

[10,242]

Exhibit ___ (MVO-1)
Schedule 4
Sheet 2 of 2

SUCCESSFUL WELL DRILLING COSTS

Line	Year	Total Footage Drilled		Successful Well Drilling Costs		
		Oil Wells (1)	Gas Wells (2)	Oil Wells (3)	Gas Wells (4)	Total (5)
		(000 Ft)		(Millions of Dollars)		
1	1959	97,188	26,538	1,720	689	2,409
2	1960	86,568	28,246	1,532	734	2,266
3	1961	85,626	29,292	1,516	761	2,277
4	1962	88,432	28,950	1,565	752	2,317
5	1963	81,809	24,533	1,448	637	2,085
6	1964	80,463	25,597	1,424	665	2,089
7	1965	73,322	24,931	1,298	648	1,946
8	1966	67,430	24,636	1,194	666	1,860
9	1967	59,800	21,482	1,058	558	1,616
10	1968	59,330	20,152	1,050	524	1,574
11	1969	58,980	21,829	1,044	567	1,611

SOURCE: Cols. (1) and (2) - World Oil, Annual Forecast and Review Issues.

Col. (3) - Col. (1) Times $17.70/Ft.

$$\$17.70 = \$11.74\ ^{1/} \times \frac{\$23.49\ ^{2/}}{\$15.58\ ^{3/}}$$

1/ Line 5 of Col. (1) of Schedule 3, Sheet 1.
2/ Line 7 of Col. (2) of Schedule 3, Sheet 2.
3/ Line 1 of Col. (2) of Schedule 3, Sheet 2.

Col. (4) - Col. (2) times $25.98/Ft.

$$\$25.98 = \$15.76\ ^{1/} \times \frac{\$37.76\ ^{2/}}{\$22.91\ ^{3/}}$$

1/ Line 5 of Col. (2) of Schedule 3, Sheet 1.
2/ Line 7 of Col. (1) of Schedule 3, Sheet 2.
3/ Line 1 of Col. (1) of Schedule 3, Sheet 2.

Col. (5) - Col. (3) plus Col. (4).

Exhibit No. 57

[10,243]

Exhibit ___(MJO-1)
Schedule 5

OTHER EXPLORATORY COSTS

Line	Year	Expenditures for Geological, Geophysical, Land Department and Lease Rentals (1) (Millions of Dollars)	Lease Acquisition Costs (2)
1	1965	610	500
2	1966	650	560
3	1967	615	860
4	1968	715	1,675
5	1969	725	1,250
6	1965-1969 Total	3,315	4,845
7	Ratio of G & G, etc. to Lease Acquisition Costs = 0.68		

SOURCE: Columns (1) & (2) - Chase Manhattan Bank.
Line 7 - Line 6 of Col. (1) Divided by Line 6 of Col. (2).

PRODUCTION EXPENSES

Line		Lease Class: Gas Only (1)	Gas Condensate: Lease Separation (2)	Gas Condensate: No Lease Separation (3)	Total (4)
1	Expenses ($000)	59,243	180,620	23,292	263,155
2	*Volume (MMcf @ 14.73 psia)	1,764,888	5,224,348	634,590	7,623,826
3	Volume (MMcf @ 14.65 psia)	1,774,524	5,252,873	638,055	7,665,452
4	Unit Expense (¢/Mcf @ 14.65)				3.43
5	Unit Expense Adjusted for 14% Royalty (¢/Mcf @ 14.65)				2.95

SOURCE: Packet B of Questionnaire Responses.
Line 1 - Sum of Lines 12, 13, 14, 15, 24, 25, 26 of Schedule 5 less Line 14 of Schedule 4.
Line 2 - Line 5 of Schedule 4 less Line 7 of Schedule 4.
Line 3 - Line 2 times $\frac{14.73}{14.65}$
Line 4 - Line 1 divided by Line 3.
Line 5 - Line 4 times 0.86.

Exhibit No. 57

[10,244]

Exhibit ___ (MJO-1)
Schedule 6

Exhibit No. 57

[10,245]

Exhibit___(MJO-1)
Schedule 7

LIQUID CREDIT DATA

	Revenue - (000 Dollars)	
1	Lease Separated Condensate	$299,419
2	Production Taxes	(16,906)
3	Lease Portion of Plant Liquids	132,578
4	Total	$415,090
	Volume (MMcf @ 14.73 psia)	
5	Production	7,630,374
6	Returned to Formation	(261,279)
7	Total @ 14.73 psia	7,630,095
8	Total @ 14.65 psia	7,671,755
9	Unit Liquid Credit	5.41¢/Mcf
10	Unit Liquid Credit Adjusted for 14% Royalty	4.65¢/Mcf

SOURCE: Packet B, Schedule 2 of Questionnaire Responses.

Line 1 - Line 11 of Col.(f).
Line 2 - Line 10 of Col. (f).
Line 3 - Line 8 of Col. (f)
Line 4 - Sum of Lines 1, 2 and 3 above.
Line 5 - Line 5 of Col. (f).
Line 6 - Line 6 of Col. (f).
Line 7 - Sum of Lines 5 and 6 above.
Line 8 - Line 7 above times $\frac{14.73}{14.65}$.

Line 9 - Line 4 above divided by Line 8 above.
Line 10- Line 9 above times 0.86.

Exhibit No. 58

[10,246]

EXHIBIT No. 58 (CSG-3)

Witness: Celia Star Gody

UNITED STATES OF AMERICA
FEDERAL POWER COMMISSION

Docket No. AR69-1

IN THE MATTER OF

AREA RATE PROCEEDING
(SOUTHERN LOUISIANA AREA)

DRILLING COST AREA
Foster Associates, Inc.
Washington, D. C.

November 1970

Exhibit No. 58

[10,250]

Schedule 1

ESTIMATED INDUSTRY-WIDE
DRILLING COSTS PER FOOT
1963-1969

Year	Gas Wells (a)	Oil Wells (b)	Dry Holes (c)
1963	$17.33	$12.96	$10.76
1964	18.65	13.23	10.88
1965	18.75	14.37	11.42
1966	21.84	15.35	12.66
1967	23.74	16.95	13.38
1968	24.41	18.15	13.31
1969	25.48	18.35	14.00

Source: Schedule 6

Exhibit No. 58

[10,277]

APPENDIX A
Sheet 1 of 3

Respondents Submitting Well Drilling Data Report, Packet A

Code No.	Status*	Company
016975		Amerada Hess Corp.
017920	N.D.	American Natural Gas Production Co.
017970	L	American Petrofina Co. of Texas
018260	N.D.	Anadarko Production Co.
029500		Ashland Oil & Refining Co.
032020		Atlantic Richfield Co.
032600		Austral Oil Co.
034500		Aztec Oil & Gas Co.
057580		Belco Petroleum Corp.
--	N.D.	Chandeleur Pipe Line Co.
089500		Gulf Oil Corp., successor in interest to British-American Oil Producing Co., The
108436		CRA, Inc.
108600		Cabot Corp.
112125		California Co.
141010		Cities Service Oil Co.
149600		E. J. Cockrell, Jr.
156500		Colorado Oil & Gas Corp.
--	N.D.	Columbia Gulf Transmission Co.
--	N.D.	Columbia Offshore Pipeline Co.
163650	L-68, A	Consolidated Gas Supply Corp.
165000		Continental Oil Co.
175500		Edwin R. Cox
205400		Del Oil and Gas Corp.
212605		Diamond Shamrock Corp.
213740	F.D., L-68	Dixilyn Corp.
213800	N.D.	Dixon Management Corp.
232360	F.D.	Eason Oil Co.
237200		El Paso Natural Gas Co.
252170		Exchange Oil & Gas Co.
273500		Forest Oil Corp.

Exhibit No. 60

[10,302]

Schedule 13

EXPLORATION AND DEVELOPMENT EXPENSES
ASSIGNED TO RESERVOIR TYPE
CONTINENTAL UNITED STATES
1969

	Assigned to Gas Reservoirs	Assigned to Oil Reservoirs	Total Assigned	Total Reported	Percent Assigned to Gas Reservoirs
	($000's)				
1. Land department; cancelled acreage; amortization of non-producing acreage; lease rentals and options	$64,588	$78,337	$142,925	$ 519,712	45.2
2. Development dry holes	47,041	78,963	126,004	136,379	37.3
3. Exploration dry holes and test well contributions	92,164	100,243	192,407	308,896	47.9
4. Geological and geophysical expense	38,436	36,649	75,086	233,749	51.2
5. Other exploration and development costs and expenses	6,490	9,195	15,685	59,013	41.4
6. Subtotal	248,719	303,387	552,107	1,257,749	45.0

Source: Packet B data composites (Exhibit Nos. ___ (RCF-1 and RCF-4)), Schedule 3. Line (1) above includes expenses reported on Lines 13, 15, 16, and 17 of Schedule 3 and Line (5) above corresponds with Line (19) of the questionnaire. It should be noted that the expenditures as reported in Schedule B for the categories listed are slightly in excess of the totals shown in Schedule D.

FA-12474*

Page 13

Exhibit No. 61

[10,306]

Exhibit No. 63

[10,323]

EXHIBIT No. 63 (SFS-1)

Witness: S. F. Sherwin

UNITED STATES OF AMERICA
FEDERAL POWER COMMISSION

Docket Nos. AR61-2, *et al.*
AR69-1

IN THE MATTER OF

AREA RATE PROCEEDINGS
(SOUTHERN LOUISIANA AREA)

ESTIMATED COST OF NEW AND SECOND VINTAGE NONASSOCIATED GAS

Foster Associates, Inc.
Washington, D. C.

January 1971

Exhibit No. 63

EXHIBIT NO. 3

ESTIMATED RANGE OF CURRENT COST OF NON-ASSOCIATED GAS

Return at 13 Percent

	Costs per Mcf at 14.73 psia		
Depletion, Depreciation, and Amortization of Production Investment Costs			
1. Successful well costs	4.75	-	4.39
2. Recompletions and deeper drilling	.21	-	.23
3. Lease acquisition costs	2.18	-	2.56
4. Other production facilities	.89	-	1.28
5. Subtotal	7.53	-	8.65
Exploration and Development Costs			
6. Dry holes	2.12	-	2.51
7. Geological and geophysical	1.44	-	2.04
8. Exploration overhead	.42	-	.50
9. Adjustment for exploration in excess of production	1.47	-	1.87
10. Subtotal	5.45	-	6.92
Other Costs and Return			
11. Production operating expense	2.90	-	3.08
12. Net liquid credit	(4.01)	-	(3.95)
13. Regulatory expense	.17	-	.17
14. Return on working capital	.55	-	.76
15. Cumulative subtotal	12.09	-	15.63

	18-Year Depletion Period	20-Year Depletion Period	18-Year Depletion Period	20-Year Depletion Period
16. Return on production investments at 1-1/2 yr. time lag	10.13	11.09	11.84	12.91
16a. at 1-2/3 yr. time lag			11.49	12.59
17. Cumulative subtotal	22.82	23.78		
18. Royalty at 15.5 percent	4.19	4.36	5.43	5.65
18a. " at 16.5 percent				
19. Production tax at 4.8%	1.36	1.42	1.80	1.88
19a. at 5.2%			34.76	36.12
20. Total cost	28.37	29.56		

[10,327]

Exhibit No. 63

[10,327]

198 e

ESTIMATED RANGE OF CURRENT COST OF NON-ASSOCIATED GAS

Return at 15 Percent

Depletion, Depreciation, and Amortization of Production Investment Costs	Costs per Mcf at 14.73 psia			
1. Successful well costs	4.14	-	4.50	
2. Recompletions and deeper drilling	.21	-	.23	
3. Lease acquisition costs	2.18	-	2.34	
4. Other production facilities	.97	-	1.58	
5. Subtotal	7.53	-	8.65	
Exploration and Development Costs				
6. Dry holes *	2.12	-	2.51	
7. Geological and geophysical	1.44	-	2.04	
8. Exploration overhead	.42	-	.50	
9. Adjustment for exploration in excess of production	1.47	-	1.87	
10. Subtotal	5.45	-	6.92	
Other Costs and Return				
11. Production operating expense	2.90	-	3.06	
12. Net liquid credit	(4.01)	-	(3.91)	
13. Regulatory expense	.17		.17	
14. Return on working capital	.80	-	.92	
15. Cumulative subtotal	12.84	-	15.80	

	18-Year Depletion Period	20-Year Depletion Period	18-Year Depletion Period	20-Year Depletion Period
16. Return on production investment at 1-1/2 yr.time lag	13.47	13.65		
16a. at 1-2/3 yr.time lag	____	____	14.58	15.95
17. Cumulative subtotal	25.31	26.49	30.38	31.75
18. Royalty at 15.5 percent	4.66	4.86		
18a. " at 16.5 percent	____	____	5.02	5.27
19. Production tax at 4.6%	1.51	1.58		
19a. " " at 5.2%	____	____	1.70	1.79
20. Total Cost	31.46	32.93	38.38	40.11

Exhibit I
Case, 5 of 8

ESTIMATED NATIONWIDE COST OF SECOND VINTAGE NONASSOCIATED GAS
Return at 13 Percent
1961-1968

	1961	1962	1963	1964	1965	1966	1967	1968
	(Cents per Mcf at 14.73 Psia)							
Depletion, Depreciation and Amortization of Production Investment Costs								
1. Successful well costs	3.16	3.15	3.13	3.25	3.21	3.75	3.99	4.16
2. Recompletions and deeper drilling	0.06	0.06	0.09	0.10	0.13	0.15	0.20	0.21
3. Lease acquisition costs	1.15	1.06	1.37	1.38	1.45	1.54	1.73	1.81
4. Other production facilities	0.57	0.60	0.63	0.68	0.71	0.86	0.96	1.04
5. Subtotal	4.94	4.87	5.22	5.41	5.50	6.30	6.88	7.22
Exploration and Development Costs								
6. Dry holes	1.83	1.91	1.83	1.80	1.87	2.05	2.07	2.14
7. Geological and geophysical	1.26	1.23	1.35	1.32	1.33	1.48	1.65	1.63
8. Exploration overhead	0.39	0.40	0.43	0.42	0.44	0.47	0.48	0.44
9. Adjustment for exploration in excess of production (37%)	1.29	1.31	1.34	1.31	1.35	1.48	1.55	1.56
10. Subtotal	4.77	4.85	4.95	4.85	4.99	5.48	5.75	5.77
Other Costs and Return								
11. Production operating expense	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00
12. Net liquid credit	(3.61)	(3.80)	(3.57)	(3.70)	(3.68)	(3.73)	(3.91)	(3.84)
13. Regulatory expense	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17
14. Return on working capital	0.44	0.42	0.48	0.48	0.50	0.53	0.57	0.59
15. Return on production investment	7.66	7.55	8.07	8.36	8.47	9.52	10.36	10.86
16. Cumulative subtotal	17.37	17.06	18.32	18.57	18.95	21.27	22.82	23.77
17. Royalty (16%)	3.31	3.25	3.49	3.54	3.61	4.05	4.35	4.53
18. Production tax	1.44	1.37	1.42	1.38	1.36	1.47	1.52	1.52
19. Total	22.12	21.68	23.23	23.49	23.92	26.79	28.69	29.82

Schedule 2
Sheet 1 of 2

[10,329]

Exhibit No. 63

[10,329]

RA-13479

200 e

ESTIMATED NATIONWIDE COST OF SECOND VINTAGE NONASSOCIATED GAS

Return at 16 Percent

1961-1968

	1961	1962	1963	1964	1965	1966	1967	1968
Depletion, Depreciation and Amortization of Production Investment Costs		(Cents Per Mcf at 14.73 Psia)						
1. Successful well costs	3.16	3.15	3.13	3.25	3.21	3.75	3.99	4.16
2. Recompletions and deeper drilling	0.06	0.06	0.09	0.10	0.13	0.15	0.20	0.21
3. Lease acquisition costs	1.15	1.06	1.37	1.38	1.45	1.54	1.73	1.81
4. Other production facilities	0.57	0.60	0.63	0.68	0.71	0.84	0.96	1.04
5. Subtotal	4.94	4.87	5.22	5.41	5.50	6.28	6.88	7.22
Exploration and Development Costs								
6. Dry holes	1.83	1.91	1.83	1.80	1.87	2.05	2.07	2.14
7. Geological and geophysical	1.16	1.23	1.35	1.32	1.33	1.48	1.65	1.63
8. Exploration overhead	0.39	0.40	0.43	0.42	0.44	0.47	0.48	0.44
9. Adjustment for exploration in excess of production (37%)	1.39	1.31	1.34	1.31	1.35	1.48	1.55	1.56
10. Subtotal	4.77	4.85	4.95	4.85	4.99	5.48	5.75	5.77
Other Costs and Return								
11. Production operating expense	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00
12. Net liquid credit	(3.61)	(3.80)	(3.57)	(3.70)	(3.66)	(3.73)	(3.91)	(3.84)
13. Regulatory expense	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17
14. Return on working capital	0.54	0.52	0.59	0.59	0.61	0.65	0.70	0.72
15. Return on production investment	9.43	9.29	9.93	10.29	10.41	11.71	12.75	13.37
16. Cumulative subtotal	19.24	18.90	20.29	20.61	21.02	23.58	25.34	26.41
17. Royalty (16%)	3.67	3.60	3.86	3.92	4.01	4.49	4.83	5.03
18. Production tax	1.59	1.51	1.57	1.54	1.51	1.63	1.69	1.69
19. Total	24.50	24.01	25.72	26.07	26.54	29.70	31.86	33.13

Schedule 2
Sheet 2 of 2

Exhibit No. 66

[10,369]

EXHIBIT No. 66 (DWA-5)
Witness: Donald W. Auten

UNITED STATES OF AMERICA
FEDERAL POWER COMMISSION

Docket Nos. AR61-2, *et al.*
AR69-1

IN THE MATTER OF

AREA RATE PROCEEDINGS
(SOUTHERN LOUISIANA AREA)

ESTIMATED COSTS OF GAS WELL GAS FLOWING IN 1969— SOUTHERN LOUISIANA AREA

Exhibit No. 66

[10,370]

Schedule 1

ESTIMATED COSTS OF GAS WELL GAS
FLOWING IN 1969
SOUTHERN LOUISIANA AREA

Line		Estimated costs @ 13% return (a)	Estimated costs @ 16% return (b)
	Production costs (Schedule 2):		
1	Cash expenses	1.99¢	1.99¢
2	DD&A	4.50	4.50
3	Return	6.30	7.75
4	Total	12.79	14.24
	R&D costs (Schedule 6):		
5	Expenses	6.61	6.61
6	Return	1.24	1.53
7	Total	7.85	8.14
8	Total production and R&D	20.64¢	22.38¢
9	Conversion to 15.025	21.05¢	22.83¢
10	Regulatory expense	.17	.17
11	Gathering costs	.51	.51
12	Production taxes	2.30	2.30
13	Total	24.03¢	25.81¢

Exhibit No. 66

[10,371]

Schedule x

SUMMARY OF PRODUCTION COSTS OF GAS WELL GAS
FLOWING IN 1969
BASED ON OPINION 546 METHODS AS ADJUSTED
SOUTHERN LOUISIANA AREA

Line		Mcf (a)	Amount (b)	Unit cost (c)
	Cash expenses:			
1	Gas only (Schedule 5)	99,316,555	$ 4,095,891	
2	Gas condensate lease separation (Schedule 3)	2,649,410,317	45,967,269	
3	Gas condensate no lease separation (Schedule 5)	108,776,315	6,737,206	
4	Total	2,857,503,187	$ 56,800,366	1.99¢
	DD&A:			
5	Gas only		$ 16,038,490	
6	Gas condensate lease separation (Schedule 3)		104,598,719	
7	Gas condensate no lease separation		7,987,696	
8	Total	2,857,503,187	$128,624,905	4.50
	Return allowance (@ 13%):			
9	Gas only (Schedule 5)		$ 23,122,653	
10	Gas condensate lease separation (Schedule 3)		129,450,188	
11	Gas condensate no lease separation (Schedule 5)		27,556,209	
12	Total	2,857,503,187	$180,129,050	6.30
13	Total production costs			12.79¢

[10,372]

Exhibit No. 66

[10,372]

Schedule 3

RELATIVE COST ALLOCATION OF GAS CONDENSATE
WITH LEASE SEPARATION LEASES
SOUTHERN LOUISIANA AREA
1969

Line		Cash expenses (a)	DD&A expenses (b)	Return allowance (c)
1	Relative cost ratios (Schedule 4)	39.680	12.376	9:195
	Joint product volumes:			
2	Liquids (D-4, L. 3)	51,466,583	51,466,583	51,466,583
3	Gas (D-4, L. 6)	2,649,410,317	2,649,410,317	2,649,410,317
4	Joint product costs (Schedule 5)	$81,386,576	$129,733,795	$152,558,532
5	Line 1 times line 2	2,042,194,013	636,950,431	473,235,231
6	Line 5 plus line 3	4,691,604,330	3,286,360,748	3,122,645,548
7	Unit cost allocated to gas (line 4 ÷ line 6)	$0.01735	$0.03948	$0.04886
8	Amount allocated to gas (line 7 times line 3)	$45,967,289	$104,598,719	$129,450,188

Schedule 4

COMPUTATION OF RELATIVE COST RATIOS
CONTINENTAL U. S.
YEAR 1969

Line		Reference: Docket and Schedule No. (a)	Reference: Line No. (b)	Cash expenses: Oil only (c)	Cash expenses: Gas only (d)	BOBA: Oil only (e)	BOBA: Gas only (f)	Net investment: Oil only (g)	Net investment: Gas only (h)
1	Production volumes	D-4	5 & 6	220,924,987	1,104,620,442	220,924,987	1,104,620,442	220,924,987	1,104,620,442
	Production expenses:								
2	Direct lease expense	D-5	12	$223,051,844	$20,623,441	$ -	$ -	$ -	$ -
3	Indirect lease expense	D-5	13	17,524,290	3,440,028	-	-	-	-
4	Taxes except income and production	D-5	14	33,011,572	8,434,030	-	-	-	-
5	Other lease expense	D-5	15	1,647,843	648,963	-	-	-	-
6	Depletion	D-5	16	-	-	80,914,533	12,081,564	-	-
7	Depreciation	D-5	17	-	-	17,794,617	12,643,373	-	-
8	Amortization	D-5	18	-	-	88,197,788	12,643,047	-	-
	Production investment:								
9	Leasehold	D-6	8	-	-	-	-	$10,118,788	188,737,608
10	Lease and well equipment	D-6	9	-	-	-	-	899,679,438	153,823,524
11	IDC costs	D-6	9	-	-	-	-	527,003,903	202,757,044
12	Related production facilities	D-6	8	-	-	-	-	101,964,734	39,539,600
13	Production buildings	D-6	10	-	-	-	-	10,200,088	2,167,677
14	Incomplete construction	D-6	11	-	-	-	-	68,089,481	19,361,131
	Less shut-in well costs:								
15	Direct lease expense	D-6-2	12	(7,640,668)	(862,188)	-	-	-	-
16	Indirect lease expense	D-6-2	13	(701,927)	(306,118)	-	-	-	-
17	Taxes	D-6-2	14	(858,720)	(107,134)	-	-	-	-
18	Other lease expense	D-6-2	15	(7,436)	4,238	-	-	-	-
19	Depletion	D-6-2	16	-	-	(713,986)	(189,808)	-	-
20	Depreciation	D-6-2	17	-	-	(3,696,014)	(822,185)	-	-
21	Amortization	D-6-2	18	-	-	(1,984,476)	(748,800)	-	-
22	Leasehold investment	D-6-2	8	-	-	-	-	(10,048,797)	(11,083,481)
23	Lease and well equipment	D-6-2	9	-	-	-	-	(28,034,283)	(17,227,481)
24	IDC costs	D-6-2	9	-	-	-	-	(29,641,538)	(23,897,089)
25	Related production facilities	D-6-2	8	-	-	-	-	(4,721,843)	(711,085)
26	Productive buildings	D-6-2	10	-	-	-	-	(602,138)	(33,484)
27	Incomplete construction	D-6-2	11	-	-	-	-	(3,679,068)	(1,417,778)
28	Less miscellaneous lease revenue	D-4	14	(1,366,865)	(888,868)	-	-	-	-
29	Total costs			$254,729,497	$27,313,813	$130,843,479	$31,729,491	$1,341,543,348	$519,079,018
30	Costs per unit produced			$0.0001	$0.0247	$0.0592	$0.0288	$6.1611	$0.0613
31	Unit cost ratio (oil only to gas only)			39.880		12.376		9.286	

[10,373]

Schedule S

COMPUTATION OF RETURN ALLOWANCE
SOUTHERN LOUISIANA AREA
YEAR 1969

Line		Gas only (a)	Gas condensate: Lease separation (b)	Gas condensate: No lease separation (c)
	Cash operating expense:			
1	Direct lease expenses, D-6, L.12	$ 2,229,747	$ 45,761,823	$ 3,059,749
2	Indirect lease expense, D-6, L.13	148,285	7,626,427	476,101
3	Taxes (except income and production), D-6, L.14	97,588	2,162,647	142,332
4	Other lease expense (not included above), D-6, L.15	140,555	2,202,492	26,353
5	Less miscellaneous lease revenues, D-6, L.16	(26,079)	(616,387)	(390,263)
	Supplemental expense:			
6	Corporate general, D-6, L.24	583,090	11,824,185	745,425
7	Area, District, Division and Field, D-6, L.25	362,155	7,496,292	805,598
8	Other expense (not included above), D-6, L.26	560,550	1,929,098	1,871,910
9	Total cash operating expenses	$ 4,095,891	$ 81,386,576	$ 6,737,206
	Working capital:			
10	1/8 of cash expense, L.9 x 1/8	$ 511,986	$ 10,173,322	$ 842,151
11	Materials and supplies, D-6, L.21	415,783	4,657,452	296,757
12	Prepayments, D-6, L.22	64,813	2,795,167	22,582
13	Total	$ 992,582	$ 17,625,941	$ 1,161,490
	Net plant investment:			
	Production investment:			
14	Leaseholds - net, D-6, L.3	$110,896,845	$ 235,304,330	$ 55,205,782
15	Lease and well equipment, D-6, L.4	20,318,911	316,342,885	17,825,773
16	Intangible development cost, D-6, L.6	29,186,760	483,053,227	33,314,628
17	Related production facilities, D-6, L.8	7,772,944	58,004,226	2,650,036
18	Production buildings, facilities and general assets (not included above), D-6, L.10	132,536	3,443,905	207,434
19	Incomplete construction applicable to production, D-6, L.11	7,611,186	38,007,476	101,118,832
	Supplemental investment (net):			
20	Corporate general, D-6, L.19	475,066	10,168,640	194,903
21	Area, District, Division and Field, D-6, L.20	414,980	10,151,251	278,560
22	Other overhead investment (not included above), D-6, L.23	64,735	1,425,286	13,404
23	Total net plant investment	$176,873,983	$1,155,901,226	$210,809,351
24	Total rate base	$177,866,565	$1,173,527,167	$211,970,841
25	Return @ 13%	$ 23,122,653	$ 152,558,532	$ 27,556,209

Schedule 6

ALLOCATION OF EXPLORATION COSTS FOR GAS RESERVOIRS
CONTINENTAL U.S.
YEAR 1969

Line		Volumes 1/ Bbl and Mcf (a)	Unit Btu's Millions (b)	Total Btu's Millions (c)	Economic factor (d)	Adjusted Btu's (e)	Allocated expense Amount (f)	Allocated expense Per unit (g)	Allocated return allowance Amount (h)	Allocated return allowance Per unit (i)
	Gas only leases:									
1	Liquids									
2	Gas	1,768,377,715	1.042	1,842,649,579		1,842,649,579				
	Gas-condensate, lease separation leases:									
3	Liquids	89,106,687	5.385	480,725,161	2.8	1,301,813,853				
4	Gas	8,301,091,117	1.067	8,860,116,044		8,860,116,044				
	Gas-condensate, no lease separation leases:									
5	Liquids									
6	Gas	713,655,281	1.146	816,702,952		816,702,952				
	Combination leases:									
7	Liquids	35,473,180	5.811	206,134,649	2.8	815,336,628				
8	Gas well gas	2,379,383,108	1.068	2,612,564,648		2,612,564,648				
	Royalties:									
9	Liquids	1,866,639	5.800	10,954,108	2.8	27,383,265				
10	Gas	173,737,913	1.100	190,011,708		190,011,708				
11	Total					13,066,379,967	$636,196,627 2/		$140,702,337 3/	
12	Total gas well gas (Lines 2, 4, 6 and 8)	10,251,609,221				11,122,029,434	$542,005,808	5.29¢	$127,838,457	1.24¢
13	Normalized expenses (Line 12 x 125%)							6.61¢		

1/ Packet D-4, lines 2 and 8, and Schedule 10

2/ Schedule 7, line 19, column j

3/ Schedule 7, line 20, column j

207 e

Exhibit No. 66

[10,375]

[10,375]

[10,376]

Exhibit No. 66

[10,376]

Schedule 7

SUMMARY OF EXPLORATION EXPENSES AND RETURN ON NET INVESTMENT AND ALLOCATION TO RESERVOIR TYPES
CONTINENTAL U.S.
YEAR 1949

Line		Total 1/ (a)	Directly assigned to reservoirs: Oil (b)	Directly assigned to reservoirs: Gas (c)	Balance to be allocated (d)	Allocation ratios (Schedule 8): Oil reservoirs (e)	Allocation ratios (Schedule 8): Gas reservoirs (f)	Allocated amounts: Oil reservoirs (g)	Allocated amounts: Gas reservoirs (h)	Total: Oil reservoirs (i)	Total: Gas reservoirs (j)
1	Exploration expenses: Development dry hole costs	$ 126,372,110	$ 78,963,813	$ 47,041,941	$ 10,372,356	62.67%	37.33%	$ 6,502,331	$ 3,872,192		
	Cost related to exploratory wells:										
2	Exploratory dry hole costs	265,615,284	94,674,665	86,525,963	113,214,656						
3	Test well contributions	13,281,072	8,368,157	3,637,995	4,274,920						
4	Total (Lines 2 and 3)	278,896,356	103,042,842	89,163,958	116,489,556	36.67%	63.33%	42,710,726	73,778,830		
	Cost related to combined exploratory and development wells:										
5	Depreciation of R&D equipment and facilities investment	20,648,181	-	-	20,648,181						
6	Other R&D cost and expenses	88,446,360	9,194,679	6,460,044	42,791,737						
7	Total (Lines 5 and 6)	79,381,831	9,194,679	6,460,044	63,606,866	65.90%	97.72	39,614,370	23,992,518		
	Cost related to acreage transfers:										
8	Land department expense	55,544,755	3,600,202	3,444,483	48,000,069						
9	Geological and geophysical expense	233,748,522	36,648,722	36,436,410	156,663,390						
10	C.S. and abandoned leases	143,077,366	23,443,339	21,030,283	97,604,764						
11	Amortization of N-P acreage	238,647,154	27,606,985	80,260,237	187,779,933						
12	Lease rentals and options	80,229,049	23,247,687	12,853,178	43,264,204						
13	Total (Lines 8 through 12)	752,249,846	114,993,978	103,024,591	533,333,318	66.81%	33.19%	225,225,661	209,798,736		
14	Total expenses before overhead (Lines 1, 4, 7 and 13)	1,277,899,883	307,282,309	248,710,836	721,804,116			414,249,998	311,439,316	$717,794,617	$960,187,048
15	Ratio of Line 14	100.00%								56.17%	43.83%
	Overhead expenses allocated to reservoir types on the basis of ratios of Line 15:										
16	Corporate general	97,385,233	-	-	97,385,233						
17	Area, District, Division and Field	76,106,806	-	-	76,106,806						
18	Total (Lines 16 and 17)	173,492,040	-	-	173,492,040	56.17%	43.83%	97,450,479	76,041,561	97,450,479	76,041,561
19	Total exploration expense (Lines 14 and 18)	$1,451,401,923	$307,282,309	$248,710,836	$895,296,156			$511,819,287	$387,479,771	$815,205,296	$636,196,627
20	Return allowance (Schedule 9, Line 13)	$ 304,216,797	$ 65,253,961	$ 24,600,335	$293,702,481	60.81%	39.19%	$178,600,479	$115,103,002	$244,554,440	$149,702,337

1/ Docket D-3, Column f

Exhibit No. 66

[10,377]

Schedule 8'

EXPLORATION ALLOCATION PERCENTAGES
CONTINENTAL U.S.
YEARS AS INDICATED

Line		Total (a)	Allocation ratios (b)
	Development dry hole costs (year 1969) (Packet B, Schedule 3, Line 11):		
1	Oil reservoirs	$ 78,962,512	62.67%
2	Gas reservoirs	47,041,243	37.33
3	Total	$ 126,003,755	100.00%
	Total expenditures for drilling successful exploratory wells (years 1963-69) (Packet A, Schedule 1):		
4	Oil wells	$ 381,982,646	36.67%
5	Gas wells	659,657,514	63.33
6	Total	$1,041,640,160	100.00%
	Total expenditures for drilling successful exploratory and development wells (years 1963-69) (Packet A, Schedule 1):		
7	Oil wells	$3,694,131,360	62.28%
8	Gas wells	2,237,523,760	37.72
9	Total	$5,931,655,120	100.00%
	Costs of acreage transferred from nonproducing to producing (years 1965-69) (Packet B, Schedule 6, Columns b through f):		
10	Gas leases (Line 1)	$ 203,087,824	28.33%
11	All other leases (Line 2)	513,712,996	71.67
12	Total	$ 716,800,820	100.00%

[10,378]

Schedule 9

EXPLORATION AND DEVELOPMENT RETURN ALLOWANCE
CONTINENTAL U.S.
1969

[10,378]

Exhibit No. 66

Line		Total (a)	Assigned to oil (b)	Assigned to gas (c)	Balance to be allocated (d)
1	Exploration expense, D-3, L.23, Column (f)	$1,451,401,923	$303,385,909	$248,719,856	$ 899,296,158
	Less noncash expenses:				
2	Cancelled and surrendered leases, D-3, L.15	142,077,386	23,442,339	21,030,283	97,604,764
3	Amortization, D-3, L.16	235,647,154	27,606,985	20,260,237	187,779,932
4	Depreciation, D-3, L.18	20,845,151	-	-	20,845,151
5	Total noncash expense	398,569,691	51,049,324	41,290,520	306,229,847
6	Cash expenses	$1,052,832,232	$252,336,585	$207,429,336	$ 593,066,311
	Working capital allowance:				
7	1/8 of cash expenses	$ 131,604,029	$ 31,542,073	$ 25,928,667	$ 74,133,289
8	Prepaid expenses, D-3, L.8	21,785,142	-	-	21,785,142
9	Materials and supplies, D-3, L.7	19,141,386	-	-	19,141,386
10	Total working capital	172,530,557	31,542,073	25,928,667	115,059,817
11	Net investment	2,860,214,035	475,796,242	240,227,759	2,144,190,034
12	Total rate base (Lines 10 and 11)	$3,032,744,592	$507,338,315	$266,156,426	$2,259,249,851
13	Return @ 13%	$ 394,256,797	$ 65,953,981	$ 34,600,335	$ 293,702,481

210 e

Exhibit No. 67

[10,381]

Schedule 1

SOUTHERN LOUISIANA AREA
ESTIMATED FLOWING GAS (VINTAGE 1) COSTS
BY SUBSTITUTION OF CURRENT COST DD&A AND E&D
1969

Line		Unit cost Low range (a)	Unit cost High range (b)
	Production costs:		
1	Cash expenses	1.93¢	1.93¢
2	DD&A	7.53	9.18
3	Return allowance	5.71	5.71
4	Total	15.17	16.82
	Exploration and development costs:		
5	Expenses	5.45	7.35
6	Return	.62	.62
7	Total	6.07	7.97
8	Subtotal @ 14.65	21.24¢	24.79¢
9	Conversion to 15.025	21.73¢	25.42¢
10	Regulatory expense	.17	.17
11	Gathering costs	.51	.51
12	Production taxes	2.30	2.30
13	Total costs @ 12% return	24.76¢	28.40¢
14	Total costs @ 13% return	25.30¢	28.94¢

Source: Opinion 546 (34 FPC 603) except for DD&A and E&D expenses which are from Dr. Stephen Sherwin's Exhibit No. _____ (SFS-1) adjusted to exclude liquid credit and royalty, and adjusted for pressure base.

Exhibit No. 69

[10,452]

Project 8,
Pinnacle A
Area
Gregory Corporation Continental U.S.
Per Year Ended _____ VOL

PRODUCTION VOLUMES AND DISPOSITION

Line No.	Description (a)	Total (b)	Loss Classification: Oil (c)	Oil Condensate (d)	Gas (e)	Gas Condensate: Loss (f)	Gas Condensate: No Loss Description (g)	Gas Condensate: No Loss Gravity (h)
	VOLUMES (GET WORKING INTEREST) AT 14.73 Psia							
1.	Liquid Production	Barrels						
2.	Crude Oil	Barrels						
3.	Lease Condensate	Barrels						
	Total Liquids (Lines 1 and 2)	Barrels						
	Gas Production (Including Cycled Gas)							
4.	Oil Well Gas	Mcf						
5.	Gas Well Gas and Gas Condensate Well Gas	Mcf						
6.	Total Gas (Line 4 and 5)	Mcf						
7.	Cycled Gas (returned to formation)	Mcf						
	ENTITLED (GET WORKING INTEREST)							
	Liquid Production							
8.	Crude Oil							
9.	Lease Condensate							
10.	Total Liquids (Line 8 and 9)							
	Gas Production							
11.	Oil Well Gas							
12.	Gas Well Gas and Gas Condensate Well Gas							
13.	Total Gas (Line 11 and 12)							
14.	Miscellaneous Lease Revenue							
	ROYALTIES RECEIVED							
15.	Total Liquids	Barrels						
16.	Total Gas	Mcf						

Exhibit No. 77

[10,532]

EXHIBIT NO. 77 (RDM-1)

Witness: Raymond D. Murr

FEDERAL POWER COMMISSION
BUREAU OF NATURAL GAS

FLOWING GAS-WELL GAS UNIT COSTS—ALLOCATION OF SOUTHERN LOUISIANA INCLUDING FEDERAL DOMAIN JOINT PRODUCTION COSTS AND CONTINENTAL U. S. EXPLORATION AND DEVELOPMENT COSTS

Docket No. AR69-1

AREA RATE PROCEEDING
(SOUTHERN LOUISIANA AREA)

Washington, D. C. 20426
January 1971

Exhibit No. 77

[10,533]

FLOWING GAS-WELL GAS UNIT COSTS—ALLOCATION OF SOUTHERN LOUISIANA INCLUDING FEDERAL DOMAIN JOINT PRODUCTION COSTS AND CONTINENTAL U. S. EXPLORATION AND DEVELOPMENT COSTS YEAR 1969

Docket No. AR69-1

AREA RATE PROCEEDING (SOUTHERN LOUISIANA AREA)

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Schedule No. 1
Sheet 1 of 1

Area Rate Proceedings
Southern Louisiana Including Federal Domain
Independent Producer and Pipeline Affiliates
Allocation and Summary of Flowing Gas-Well Gas Production Costs
Year 1969

Summary of Unit Production Costs from Gas Only and Gas Condensate Leases

Line No.	Description	Gas Only and Gas Cond. Lease Volumes (Mcf)	Total $	Total c/Mcf	Cash Expense (Excl. Production Taxes) $	Cash Expense (Excl. Production Taxes) c/Mcf	DD & A Expense $	DD & A Expense c/Mcf	Return @ 13% $	Return @ 13% c/Mcf
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
1.	Gas Only	99,296,948	41,369,821	41.663	3,293,093	3.316	15,604,679	15.715	22,472,049	22.631
2.	Gas Cond. - No									
3.	Lease Separation	108,776,315	41,246,522	37.919	6,142,479	5.647	7,817,250	7.187	27,286,793	25.085
4.	Gas Cond. - With									
5.	Lease Separation	2,908,147,670	268,470,933	9.232	46,780,229	1.609	101,296,022	3.483	120,394,682	4.140
6.										
7.	Total	3,116,220,933	351,087,276	11.266	56,215,801	1.804	124,717,951	4.002	170,153,524	5.460
8.										

9. Allocation of Joint Production Costs for Gas Condensate - Lease Separation Leases

Line No.	Description	Volume Mcf or bbl	Single Product Unit Cost $/Mcf or $/bbl	Related Computed Expense and Return $	Allocation Percentages %	Joint Production Costs as Allocated $	Reference Line	Reference Col.	Source of Data Exh.	Source of Data Sch.	Source of Data Col.	Source of Data Line
	(a)	(b)	(c)	(d)	(e)	(f)						
17.	Cash Expense											
18.	Lease Liquids	36,780,594	1.0310	38,540,792	46.956	41,411,138	1,3,5	b	RDM-1	3	b,c,k	9
19.	Raw Gas	2,908,147,670	0.02274	66,131,278	53.044	46,780,229	1,3	e	EOB-1	1	i,k	7-1
20.	Total			124,672,070	100.000	88,191,367	1,3	g	EOB-1	1	i,k	8
21.							1,3	i	EOB-1	1	i,k	10
22.	DD & A						5	e	RDM-1	1	f	19
23.	Lease Liquids	36,780,594	0.5849	33,210,969	24.612	33,070,219	5	g	RDM-1	1	f	24
24.	Raw Gas	2,908,147,670	0.03498	101,727,005	75.388	101,296,022	5	i	RDM-1	1	f	29
25.	Total			134,937,974	100.000	134,366,241	18,19	b	RDM-1	3	c,e	9
26.							18,19	e	RDM-1	2	b,c	9
27.	Return @ 13%						20	f	EOB-1	1	j	7-1
28.	Lease Liquids	36,780,594	13.7387	780,091,547	26.049	42,408,636	23,24	e	RDM-1	2	b,c	16
29.	Raw Gas	2,908,147,670	0.76133	2,214,641,695	73.951	120,394,682	25	f	EOB-1	1	j	8
30.	Total			2,994,733,242	100.000	162,803,318	28,29	e	RDM-1	2	b,c	17
							30	f	EOB-1	1	j	8

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[10,534]

Exhibit No. 77

[10,534]

[10,535]

Exhibit No. 77

[10,535]

Schedule No. 2
Sheet 1 of 1

Area Rate Proceedings
Southern Louisiana Including Federal Domain
Independent Producers and Pipeline Affiliates
Calculation of Continental U.S. "Oil Leg" and "Gas Leg" Unit Costs
Year 1969

Line No.	Description (a)	Oil Only (b)	Gas Only (c)	Source of Data: Reference Line	Reference Cols.	Schs.	Cols.	Lines
1.	Production Volumes							
2.	Lease Liquids (Bbls.)	276,342,145		2	b	RDM-1	4	b
3.	Lease Gas (Mcf)		1,714,815,186	3	c	RDM-1	4	c
4.				4	b,c	EDB-1	11	m,n 12, 13, 14, 15
5.	Cash Expenses (Less Production Taxes)	287,313,920	39,635,014	5	b,c	RCF-3	5-1	c,e 12, 13, 14, 15
6.	Less Shut-In	348,087	637,228	12	b,c	EDB-1	11	m,n 16, 17, 18
7.	Adjusted Cash Expenses	286,965,833	38,997,786	13	b,c	RCF-3	5-1	c,e 16, 17, 18
8.				19	b,c	EDB-1	11	m,n 1, 3, 5, 7, 9, 11
9.	Unit Cash Expense ($/Bbl.) and ($/Mcf)	1.0010	0.02274	20	b,c	RCF-3	5-1	c,e 1, 3, 5, 7, 9, 11
10.								
11.								
12.	DD&A Expenses	164,539,013	61,011,021					
13.	Less Shut-In	1,749,674	1,033,770					
14.	Adjusted DD&A Expenses	162,789,339	59,977,251					
15.								
16.	Unit DD&A Expense ($/Bbl.) and ($/Mcf)	0.5849	0.03498					
17.								
18.								
19.	Gross Investment	3,874,377,601	1,384,774,647					
20.	Less Shut-In	50,306,575	78,889,282					
21.	Adjusted Gross Investment	1,824,071,026	1,305,885,365					
22.								
23.	Unit Gross Investment ($/Bbl.) and ($/Mcf)	13.7387	0.76153					

Schedule No. 3
Sheet 1 of 1

Area Rate Proceedings
Southern Louisiana Including Federal Domain
Independent Producers and Pipeline Affiliates
Production Volume Adjustments
Year 1969

Line No.	Description (a)	Gas-Well Gas - Mcf: Gas Only Lease (b)	Gas-Well Gas - Mcf: Gas Condensate Leases: With Lse. Sep. (c)	Gas-Well Gas - Mcf: Gas Condensate Leases: No Lse. Sep. (d)	Gas Condensate Lease Liquids Bbls. (e)
1.	Production Volume 1/	99,316,555	2,926,350,229	108,776,315	57,057,322
2.					
3.	Staff Adjustment 2/				
4.	Del Oil & Gas Corporation	(15,827)			
5.	Diamond Shamrock Corporation		(2,979,009)		(35,073)
6.	Samedan Oil Corp.		(712,741)		(17,031)
7.	Transocean Oil, Inc.	(3,780)	(14,510,809)		(224,624)
8.					
9.	Adjusted Production Volumes	99,296,948	2,908,147,670	108,776,315	56,780,594

Source References:

1/ Exhibit No. ___(RCF-3), Schedule 4.

2/ Respondent Filing.

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[10536]

Exhibit No. 77

[10536]

[10,537]

Exhibit No. 77

[10,537]

Schedule No. 4
Sheet 1 of 1

Area Rate Proceedings
Southern Louisiana Area
Independent Producers and Pipeline Affiliates
Continental U.S. "Oil Leg" and "Gas Leg" Production Volume Adjustment
Year 1969

Line No.	Description (a)	Oil Leg Volumes Bbl (b)	Gas Leg Volumes Mcf (c)
1.	Production Volumes 1/	279,487,751	1,718,002,048
2.			
3.	Revisions 2/		
4.	Union Texas Petroleum		(7,102,051)
5.			7,014,356
6.			
7.	Staff Adjustments 2/		
8.	American Petrofina	(14,008)	(453,838)
9.	Del Oil and Gas	(136,998)	(15,827)
10.	Magna		
11.	Samedan	(745,296)	(2,080,250)
12.	Transocean	(249,304)	(549,252)
13.			
14.	Adjusted Composite	278,342,145	1,714,815,186

Source of Data:

1/ Exhibit No. ___(RCF-3), Schedule 4.

2/ Respondent Filing.

Exhibit No. 77

[10,538]

Schedule No. 5
Sheet 1 of 1

Area Rate Proceedings
Southern Louisiana Area
Independent Producers and Pipeline Affiliates
Summary of Exploration and Development Unit Costs for
Gas-Well Gas Using a Range of Economic Factors
for Liquids and 1.0 for Gas
Continental U.S. Data
Year 1969

Line No.	Economic Factor (a)	E&D Unit Cost - ¢/Mcf: Modified Btu Method 1/ (b)	E&D Unit Cost - ¢/Mcf: Direct Assignment to Reservoirs 2/ (c)
1.	2.0	5.330	6.752
2.	2.1	5.173	6.716
3.	2.2	5.026	6.680
4.	2.3	4.886	6.644
5.	2.4	4.755	6.609
6.	2.5	4.630	6.574
7.	2.6	4.511	6.540
8.	2.7	4.399	6.506
9.	2.8	4.292	6.471
10.	2.9	4.190	6.438
11.	3.0	4.093	6.405
12.	3.1	4.000	6.373
13.	3.2	3.911	6.340
14.	3.3	3.826	6.308
15.	3.4	3.745	6.275
16.	3.5	3.667	6.244

Source References:

1/ Schedule 7.

2/ Schedule 9.

[10,539]

Exhibit No. 77

[10,539]

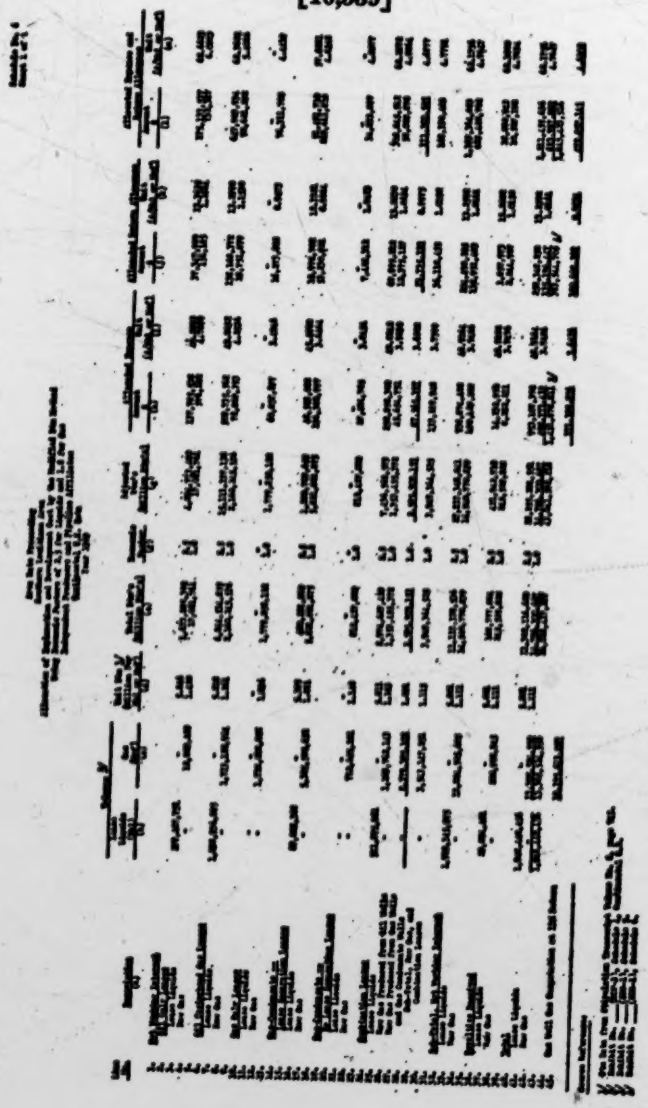

Exhibit No. 77

[10,540]

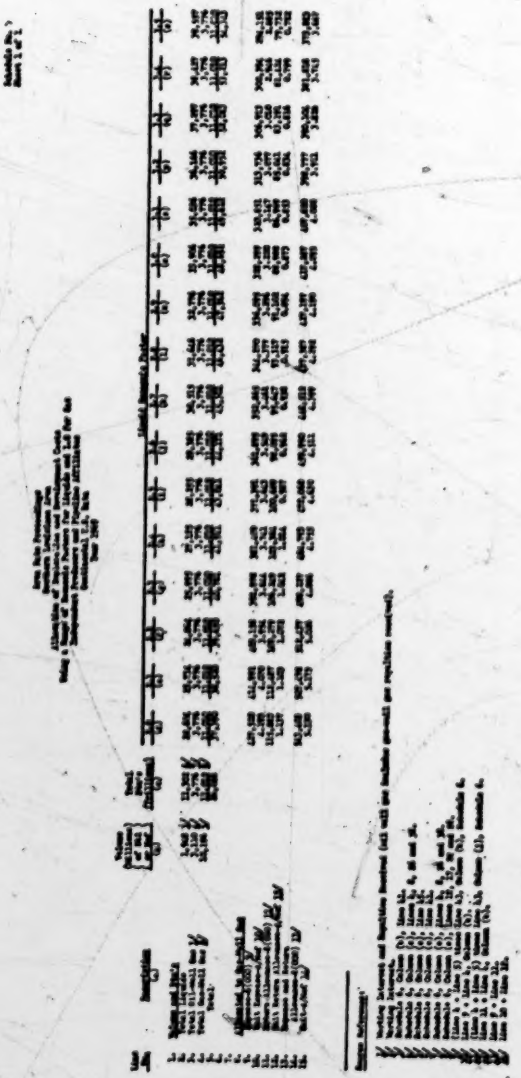

Exhibit No. 77

[10,541]

Exhibit No. 77

[10,542]

Schedule No. 6
Sheet 2 of 2

Area Rate Proceedings
Southern Louisiana Area
Independent Producers and Pipeline Affiliates
Direct Assignment of Exploration and Development Costs to Oil and Gas Reservoirs
Continental U.S.
Year 1969

Line No.	Description (a)	Expenses and Investment Assigned to Reservoirs (b)	Percent Totals (c)	Expenses and Return Allowance Allocated (d)
1.	Exploration and Development Costs			
2.	Expenses			
3.	Oil Reservoirs	303,385,909 1/	54.984	798,301,045
4.	Gas Reservoirs	248,383,449 1/	45.016	653,577,766
5.	Total	551,769,358	100.000	1,451,878,811 2/
6.				
7.				
8.	Investment and Return Allowance			
9.	Oil Reservoirs	475,796,242 1/	66.502	261,715,100
10.	Gas Reservoirs	239,670,409 1/	33.498	131,829,605
11.	Total	715,466,651	100.000	393,544,705 3/

Source Reference:

1/ Exhibit No. ___(RCF-1), Packet B, Schedule 3.

2/ Exhibit No. ___(EOB-1), Schedule 5.

3/ Exhibit No. ___(EOB-1), Schedule 6.

Exhibit No. 77

[10,543]

Exhibit No. 80

[10,550]

EXHIBIT No. 80 (WTL-1)

Witness: William T. Loring

FEDERAL POWER COMMISSION
BUREAU OF NATURAL GAS

ESTIMATED CURRENT, NATIONWIDE COST OF FINDINGS AND PRODUCING NON-ASSOCIATED NATURAL GAS

Docket No. AR69-1

AREA RATE PROCEEDING
SOUTHERN LOUISIANA AREA

Washington, D. C. 20426
January, 1971

Exhibit No. 80

[10,555]

Schedule No. 2
Sheet 1 of 1

Area Rate Proceeding
(Southern Louisiana Area)
Average Drilling Cost, Dollars per Foot
United States, 1969

Line No.	Description	1969 Average Cost per Foot
	(a)	(b)
1.	Gas Wells	$25.58
2.	Dry Holes	13.23

Source: Joint Association Survey (Section I), Drilling Cost, November, 1970, page 2.

Area Rate Proceeding
(Southern Louisiana Area)
Gas-Well Gas Found Per Successful Gas Well Foot
Drilled and Ratio of Findings to Production
U.S. 1964-1969

Line No.	Year (a)	Gross Findings @ 14.65 Psia (Thousands of Mcf) (b)	Successful Gas Well Footage Drilled (c)	Findings Per Foot (Mcf) (d)	Production @ 14.65 Psia (Thousands of Mcf) (e)	Ratio of Findings to Production (f)
1.	1964	17,461,778	25,597,346	682	11,526,833	1.51
2.	1965	18,466,450	24,930,859	741	12,231,119	1.51
3.	1966	17,129,629	25,635,979	668	13,166,116	1.30
4.	1967	18,061,763	21,481,984	841	13,786,667	1.31
5.	1968	14,055,303	20,151,701	697	14,904,273	0.94
6.	1969	6,892,150	21,828,810	316	16,058,953	0.43
7.	1964-1968	85,174,923	117,797,869	723		
8.	1965-1969	74,605,295	114,029,333	654		

Sources:

Col. (b): "Report of the Committee on Natural Gas Reserves of the American Gas Association," Part II of the report entitled "Reserves of Crude Oil, Natural Gas Liquids and Natural Gas in the U.S. and Canada as of December 31, 1969." Volume 24, May 1970.

Col. (c): World Oil Magazine, Annual Forecast Review Issues (February 15).

Col. (d): Col. (b) divided by Col. (c).

Col. (e): From same source as Col. (b).

Col. (f): Col. (b) divided by Col. (e).

[10,556]

Exhibit No. 81

[10,571]

EXHIBIT No. 81 (AEW-1)

BEFORE THE
FEDERAL POWER COMMISSION

Docket No. AR69-1

AREA RATE PROCEEDING
(SOUTHERN LOUISIANA AREA)

CEILING PRICES SET FOR SOUTHERN LOUISIANA AREA IN FPC OPINIONS NO. 546 & 546A AND COST UNDERPINNING THEREOF

Van Scoyoc & Wiskup, Inc.
Public Utility Consultants
1735 K Street, Northwest
Washington, D.C. 20006

Exhibit No. 81

[10,572]

229 e

Exhibit No. 83

[10,588]

EXHIBIT No. 83 (AEW-3)

BEFORE THE
FEDERAL POWER COMMISSION

Docket No. AR69-1

AREA RATE PROCEEDING
(SOUTHERN LOUISIANA AREA)

COMPARISON OF COST OF FLOWING GAS WELL GAS, 1969 TEST PERIOD VERSUS 1960 TEST PERIOD

Van Scoyoc & Wiskup, Inc.
Public Utility Consultants
1735 K Street, Northwest
Washington, D.C. 20006

AREA RATE PROCEEDING
DOCKET NO. AR69-1 SOUTH LOUISIANA AREA

COMPARISON OF COST OF FLOWING GAS
WELL GAS, 1969 TEST PERIOD VERSUS 1960 TEST PERIOD

Schedule No. 1

Line No.	Description (1)	1969 Test Year 12% Rate of Return @14.73 psia (2)	1969 Test Year 12% Rate of Return @15.025 psia (3)	1969 Test Year 13% Rate of Return @15.025 psia (4)	1960 Test Year Opinion No. 546 12% Rate of Return @15.025 psia (5)
1	Cost of Producing and Gathering Gas:				
2	Production Expenses	1.84¢	1.88¢	1.88¢	1.93¢
3	Depreciation, Depletion & Amort.	4.03¢	4.11¢	4.11¢	3.27¢
4	Regulatory Expense	.17¢	.17¢	.17¢	.17¢
5	Area Gathering	.50¢	.51¢	.51¢	.51¢
6	Return Allowance	5.03¢	5.13¢	5.56¢ 1/	5.85¢
7	Louisiana Production Tax	2.25¢	2.30¢	2.30¢	2.30¢
8	Total	13.82¢	14.10¢	14.53¢	14.03¢
9	Cost of Finding and Developing Gas:				
10	Exploration and Development Expenses	2.90¢	2.96¢	2.96¢	3.64¢
11	Return Allowance	.73¢	.74¢	.80¢ 2/	.64¢
12	Total	3.63¢	3.70¢	3.76¢	4.28¢
13	Total All Costs	17.45¢	17.80¢	18.29¢	18.36¢

1/ $\frac{13}{12}$ x 5.13

2/ $\frac{13}{12}$ x .74

[10,592]

Exhibit No. 85

[10,592]

SOUTH LOUISIANA GAS TRANSMISSION COMPANIES

TRANSMISSION COST OF SERVICE

	Company	Docket No.	Transmission Cost of Service: Operating Expenses	Depreciation Expense	Other Taxes	Return	Federal Income Tax	Allocated Other Functions	Revenue Credit	Total
1.	Columbia Gulf Transmission Company	RP71-18	$ 19 925 403	$ 28 652 262	$ 7 140 134	$ 34 806 330	$ 21 576 971	$ -	$ (198 620)	$ 111 902 480
2.	Natural Gas Pipeline Company	RP70-35	49 863 600	37 499 693	12 606 005	65 257 565	33 037 164	-	(5 093 878)	193 170 149
3.	Southern Natural Gas Company	RP70-36	29 787 275	26 175 685	7 645 532	34 482 148	25 511 468	-	(1 187 667)	122 414 441
4.	Tennessee Gas Pipeline Company	RP71-6	65 059 546	67 192 609	19 454 179	104 176 334	66 841 222	(12 953 086)	-	309 830 804
5.	Texas Eastern Transmission Corporation	RP70-29	46 536 709	43 369 973	15 299 724	79 909 514	41 041 075	(24 959 130)	-	201 197 865
6.	Texas Gas Transmission Corporation	RP69-41	24 997 599	16 409 421	6 578 482	27 346 008	17 077 365	-	(489 367)	91 919 608
7.	Trunkline Gas Company	RP69-4	16 520 246	13 379 459	4 657 324	23 215 721	7 583 358	-	(6 093 745)	58 262 244
8.	Total		$252 670 378	$232 679 082	$73 361 380	$369 293 630	$213 668 626	$ (37 912 216)	$(13 063 177)	$1 088 697 501

EXHIBIT NO. 85
WITNESS: W. F. Anderson
Page 2
(1-74)

Exhibit No. 90

[10,629]

EXHIBIT No. 90 (BGC-1)

Witness: Baker G. Clay

UNITED STATES OF AMERICA
FEDERAL POWER COMMISSION

Docket Nos. AR61-2 and AR69-1

IN THE MATTER OF
AREA RATE PROCEEDINGS, *et al.*:

Southern Louisiana
Annual and Unit Cost of Gas
to Certain Pipe Lines and Annual and
Unit Revenues to Certain Producing Companies Under
Effective Rates, Opinion 546 Rates
and Proposed Settlement Rates

Year 1970

SOUTHERN LOUISIANA AREA RATE PROCEEDING
1970 Annual Purchases and Annual and Unit Cost of Gas
of Interstate Pipeline Companies Under:
(a) Effective Rates; (b) Opinion 546 Rates; and (c) NGC Proposed Settlement Rates
Volumes in Mcf @ 15.025 psia and Revenues in Thousands of Dollars

Line No.	Company (Column 1)	1970 Annual Purchases 1/ (2)	Cost of Effective Rates 2/ Total (3)	Cost of Effective Rates 2/ Unit (4)	Cost at Opinion 546 Rates Unit (5)	Cost at Opinion 546 Rates Below Effective Rates Annual (6)	Cost at Opinion 546 Rates Below Effective Rates Unit (7)	Cost at Proposed Settlement Rates Unit (8)	Cost at Proposed Settlement Rates Above Effective Rates Annual (9)	Cost at Proposed Settlement Rates Above Effective Rates Unit (10)
1	Bluebonnet	1,650	$ 244	14.90¢	14.90¢	-	-¢	14.90¢	$ -	-¢
2	Florida Gas	81,371	15,926	19.57	19.16	339	.41	19.08	365	.45
3	Michigan Wisconsin	238,990	44,786	20.13	18.54	5,221	1.59	21.20	3,445	1.05
4	Natural Gas Pipeline	134,056	26,963	20.11	18.71	1,879	1.40	20.28	229	.17
5	Southern Natural	428,327	84,019	20.58	18.54	8,301	2.04	22.00	5,821	1.43
6	South Texas	3,098	610	19.69	19.69	-	-	24.69	135	5.00
7	Tennessee 3/	821,336	167,405	20.38	18.31	18,698	2.03	21.54	11,270	1.22
8	Texas Eastern	330,897	63,978	19.34	18.52	2,712	.82	20.50	3,639	1.16
9	Texas Gas	441,235	87,557	19.84	18.65	5,264	1.19	21.27	6,295	1.43
10	Transco	677,001	133,894	19.78	18.05	11,720	1.73	21.53	11,690	1.75
11	Trunkline	282,276	57,779	20.47	18.34	6,387	2.13	21.59	3,158	1.12
12	United Fuel and Columbia Gulf	486,948	98,546	20.24	18.59	8,001	1.65	21.53	6,282	1.29
13	United Gas Pipe Line	832,137	168,209	20.22	18.54	15,951	1.67	22.37	17,889	2.15
14	Valley Gas Transmission	4,158	696	16.70	16.70	-	-	16.70	-	-
15	Total	4,933,676	$992,105	20.11¢	18.43¢	682,470	1.68¢	21.54¢	870,458	1.45¢

	Onshore	Offshore
Contracts dated Pre 1/1/61*	18.5¢	17.0¢
Contracts dated 1/1/61-10/1/68	19.5	18.0
Contracts dated Post 10/1/68	20.0	18.5

*All well gas in all vintages receives pre 1/1/61 price.

	Onshore	Offshore
Contracts dated Pre 10/1/68	22.375¢	21.375¢
Contracts dated Post 10/1/68	26.0	26.0

1/ Includes Jupiter
2/ 1968 Purchases (From Staff's tape) Adjusted to 1970 levels.
3/ Rates effective as of 1/1/70.

Exhibit No. 90

[10,631]

Exhibit No. 90 (SEC-1)
Schedule 7

EXTENDED SOUTHERN AREA RATE PROCEEDING
1970 Annual Rates and Annual and Unit Revenues of Certain Producing Companies
Subject (a) Effective Rates; (b) Certain Issues Set for Hearing; (c) SEC Proposed Settlement Rates
Volume in MMcf @ 15.025 psia and Revenues in Thousands of Dollars

Line No.	Company Column 1	1970 Annual 1/ Sales (2)	Revenue at Effective Rates 1/ 2/ Annual (3)	Unit (4)	Revenue at Certain Set Rates Below Effective Rates Annual (5)	Unit (6)	Dollars Difference (7)
1	Amerada	24,243	* 4,789	19.754	18,454	* 260	1.072
2	Amerada Hess	211,337	42,341	19.91	3,110	1,232	1.788
3	Amerada Petroleum	211,337	42,341	19.91	3,110	1,232	1.788
4	California Company	34,243	6,591	19.24	5,574	1,136	1.017
5	Cities Service Co.	34,243	6,591	19.24	5,574	1,136	1.017
6	Forest	34,243	6,777	19.79	5,574	1,202	1.203
7	General American	114,134	23,088	20.23	18,582	4,506	4.506
8	Getty	114,134	23,088	20.23	18,582	4,506	4.506
9	Gulf	457,393	93,488	20.44	74,493	18,995	18.995
10	Humble 3/	445,198	91,124	20.47	72,299	18,825	18.825
11	Kerr-McGee	21,921	4,598	20.97	3,497	1,101	1.101
12	Mobil	70,429	14,768	20.96	11,237	3,531	3.531
13	Mobil Interests 3/	21,921	4,598	20.97	3,497	1,101	1.101
14	Murphy	70,429	14,768	20.96	11,237	3,531	3.531
15	Shell	291,443	59,844	20.53	46,497	13,347	13.347
16	The Superior	291,443	59,844	20.53	46,497	13,347	13.347
17	Pennzoil	63,620	13,433	21.11	11,333	2,100	2.100
18	Phillips	63,620	13,433	21.11	11,333	2,100	2.100
19	Placid	47,055	10,363	22.03	7,803	2,560	2.560
20	Sun	47,055	10,363	22.03	7,803	2,560	2.560
21	Sun & Sunray DX	114,348	23,834	20.84	18,341	5,493	5.493
22	Superior	114,348	23,834	20.84	18,341	5,493	5.493
23	Texaco	288,033	59,233	20.57	46,437	12,796	12.796
24	Union Oil of California	90,973	19,919	21.90	15,717	4,202	4.202
25	Union Texas	90,973	19,919	21.90	15,717	4,202	4.202
26	Other 3/	333,538	69,252	20.76	52,434	16,818	16.818
27	Total Industry 3/	4,333,474	890,103	20.54	698,478	191,625	191.625

	Dollars	Difference
Contracts dated Pre 12/1/70	18.54	11.04
Contracts dated 12/1/70-10/1/70	19.5	18.0
Contracts dated Post 10/1/70	20.0	14.5

Will get in all vintages receive pre 1/1/61 price.

	Revenue at Proposed Settlement Rates Above Effective Rates					
	Unit (8)	Annual (9)		Unit (10)		
	19.454	* 341		1.454		
	20.345	2,157		1.235		
	20.345	2,157		1.235		
	20.345	1,136		1.136		
	20.345	1,136		1.136		
	20.345	1,202		1.202		
	20.345	4,506		4.506		
	20.345	4,506		4.506		
	20.345	18,995		18.995		
	20.345	18,825		18.825		
	20.345	3,497		1.101		
	20.345	11,237		3.531		
	20.345	3,497		1.101		
	20.345	11,237		3.531		
	20.345	11,341		3.553		
	20.345	11,341		3.553		
	20.345	7,803		2.560		
	20.345	7,803		2.560		
	20.345	18,341		5.493		
	20.345	18,341		5.493		
	20.345	46,437		12.796		
	20.345	15,717		4.202		
	20.345	15,717		4.202		
	20.345	52,434		16.818		
	20.345	698,478		191.625		
	Contracts dated Pre 10/1/70			21.376		26.0
	Contracts dated Post 10/1/70			21.376		26.0

1/ Includes Elm Lake
2/ Includes H. L. Hunt, Ranch Root Trust, Hunt Oil Co. and Caroline Hunt Trusts and Lloyd N. Hunt.
3/ Total Industry (Line 27) minus sum of Lines 1-25.
Line 13 (Mobil Interests) = Exhibit No. (SEC-2)
Line 26 (Other Small's sum) adjusted to 1970 level.
Rates effective as of January 1, 1970.

Exhibit No. 91

[10,632]

EXHIBIT No. 91 (BGC-2)

Witness: Baker G. Clay

UNITED STATES OF AMERICA
FEDERAL POWER COMMISSION

Docket Nos. AR61-2 and AR69-1

IN THE MATTER OF
AREA RATE PROCEEDINGS, *et al.*:

Southern Louisiana
Sales Volumes, Revenues, Refunds and
Unit Realization of Certain Producing
Companies Under Effective Rates, Opinion
546 Rates and Proposed Settlement Rates

Years 1960-1970

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SOUTHERN LOUISIANA AREA RATE PROCEEDINGS
Interstate Sales Volumes, Revenues, Refunds and Unit Realization
of Certain Large Producing Companies Under:
(a) Effective Rates; (b) Opinion 546 Rates; and, (c) UDC Proposed Settlement Rates
Volumes in Mmcf @ 15.025 psia; Revenues and Refunds in Thousands of Dollars

Line No.	Year Column 1	Sales Volumes (2)	Revenues Per Books: Gross Revenues (3)	Refunds (4)	Retained Revenues (5)=(3)-(4)	Unit Realization (6)=(5)÷(2)	Opinion No. 546 Rates: Refund Obligation (7)	Retained Revenues (8)=(5)-(7)	Unit Realization (9)=(8)÷(2)	Proposed Settlement Rates: Refund Obligation (10)	Retained Revenues (11)=(5)-(10)	Unit Realization (12)=(11)÷(2)
1	Pre 1960	-	$ -	$ -	$ -	-¢	$ 1,827	$ -	-¢	$ 1,075	$ -	-¢
2	1960	1,979,610	388,408	8,023	380,386	20.32	4,791	375,595	19.97	3,834	277,552	20.11
3	1961	1,696,287	317,735	15,992	301,743	20.17	6,738	295,005	19.72	3,992	297,771	19.90
4	1962	1,726,810	359,696	20,574	339,120	19.62	8,939	330,181	19.10	5,631	333,489	19.30
5	1963	1,976,713	408,442	15,560	387,882	19.62	9,310	378,572	19.15	5,634	382,248	19.34
6	1964	2,189,544	438,725	9,752	428,973	19.59	9,956	419,017	19.14	5,966	423,007	19.32
7	1965	2,393,340	472,349	4,382	467,967	19.55	12,278	455,689	19.04	5,529	462,438	19.32
8	1966	2,755,780	547,043	1,195	546,668	19.84	16,605	530,063	19.23	7,308	539,160	19.56
9	1967	3,100,088	618,952	943	618,709	19.95	21,848	596,861	19.23	8,889	609,820	19.65
10	1968	3,530,686	715,543	139	715,404	20.22	36,572	678,832	19.18	11,635	703,769	19.89
11	1969	4,022,333	812,825	2	812,823	20.16	63,333	749,290	18.58	19,383	793,440	19.68
12	1970	4,875,831 1/	862,778 2/	-	862,778	20.18	63,333	799,245	18.69	19,383	843,395	19.72
13	Subtotal			$75,882		19.96¢	$255,930		19.08¢	$ 97,279		19.63¢
14	Interest	-	-	-	-	-	54,628	-	-	25,840	-	-
15	Total Sample (82.3%)	-	-	-	-	19.96¢	$310,558	-	19.08¢	$123,119	-	19.63¢
16	Grand Total 2/	-	-	-	-	19.96¢	$376,628	-	19.08¢	$149,220	-	19.63¢

237 e

All Sales	Onshore	Offshore
Contracts Dated Pre 1/1/61*	18.5¢	17.0¢
Contracts Dated 1/1/61-10/1/68	19.5	18.0
Contracts Dated Post 10/1/68	20.0	18.5

*All oil well gas priced at rates shown for this vintage.

	Onshore	Offshore
Sales Prior to 1/1/65	20.625¢	19.625¢
Sales 1/1/65-10/1/68	21.25	20.25
Sales 10/1/68-1/1/71	*	*

*Refunds at 30.5% of Opinion 546 Refunds

Source:
Columns (2), (3) and (4) - Responses to UDC Sales and Revenue Questionnaire.
Columns (7) and (10) - Computer Runs.

1/ Where data was not provided by the individual producer, 1970 sales and revenues were assumed to be the same as 1969.
2/ Factored up on the basis that sales for the sample companies amounted to 82.3% of the total in 1968.

Exhibit No. 91
[10,633]
Docket No. 27 (Sub-1)
[10,633]

Exhibit No. 92

[10,634]

EXHIBIT No. 92 (BGC-3)

Witness: Baker G. Clay

UNITED STATES OF AMERICA
FEDERAL POWER COMMISSION

Docket Nos. AR61-2 and AR69-1

IN THE MATTER OF
AREA RATE PROCEEDINGS, *et al.*:

Southern Louisiana
Cost of Gas Adjusted to Include
Weighted Average Production Tax

1960, 1962 and 1969

238 e

SOUTHERN LOUISIANA AREA
Cost of Gas
1960, 1962 and 1969

	1960	1962	1969
Low Cost			
Without Tax 1/	16.0	17.5 3/	18.4 4/
Production Tax	2.2 2/	2.1	1.9
Total	18.2	19.6	20.3
Middle Cost			
Without Tax 1/	19.9	21.4 3/	21.9 4/
Production Tax	2.2 2/	2.1	1.9
Total	22.1	23.5	23.8
High Cost			
Without Tax 1/	25.3	26.5 3/	27.9 4/
Production Tax	2.2 2/	2.1	1.9
Total	27.5	28.6	29.8

1/ Exhibit 56
2/ .9344 x 2.3¢
3/ .9006 x 2.3¢
4/ .8046 x 2.3¢

Exhibit No. 93

[10,636]

EXHIBIT No. 93 (BGC-4)

Witness: Baker G. Clay

UNITED STATES OF AMERICA
FEDERAL POWER COMMISSION

Docket Nos. AR61-2 and AR69-1

IN THE MATTER OF

AREA RATE PROCEEDINGS, *et al.*:

Southern Louisiana
Graphic Comparison of Cost and
Revenue Studies

Years 1960-1970

Exhibit No. 93

[10,637]

Exhibit No. 96

[10,644]

Docket No. AR69-1
EXHIBIT No. 96 (DLK-1)

RATE DESIGN PROPOSAL
FOR
SOUTHERN LOUISIANA AREA

Exhibit No. 96

[10,648]

SECTION 3. CEILING PRICES.

3.1 *Ceiling Prices in General.*

Commencing with the Effective Date, the ceiling prices per Mcf, subject to adjustment pursuant to other provisions hereof, applicable to all jurisdictional deliveries made under contracts subject hereto for sales of gas produced in the Southern Louisiana Area are as follows:

(a) Contracts Dated Prior to October 1, 1968:

Onshore	24.0¢
Offshore*	23.0¢

* Subject to Section 8 hereof, Onshore ceiling prices will apply to Disputed Zone gas.

(b) Contracts Dated On or After October 1, 1968:**

Onshore	30.0¢
Offshore	30.0¢

** Includes contracts set out in Appendix B of Opinion No. 546-A and any other existing contracts ultimately treated in a similar fashion by the Commission, prospectively from the date of the Commission's order regarding such contract.

[10,657]

SECTION 7. REFUNDS AND DISPOSITION THEREOF.

7.1 Subject to Section 8 hereof, as to amounts collected by all producers under sales from the Southern Louisiana

[10,657]

Exhibit No. 96

Area subject to refund under a Commission order in the proceedings in (1) Docket Nos. AR61-2, *et al.*; (2) Docket No. AR69-1; (3) *Union Texas Petroleum, et al.*, Docket Nos. G-13221, *et al.*, together with all dockets covered by Opinion No. 575; (4) any pending rate suspension dockets not consolidated in Docket Nos. AR61-2, *et al.*, except amounts based on differences in contract interpretation; (5) any proceeding involving an increase in rate filed on or after January 10, 1971, and (6) any other pending certificate docket covered hereby, refunds shall be calculated in the following manner:

(a) With respect to deliveries made prior to January 10, 1971, the ceiling prices per Mcf set out below, as adjusted by the terms of Sections 2.3 and 3.4, shall apply to all producers. Revenues collected subject to refund in excess of the ceiling prices per Mcf set out below, together with applicable interest, shall be calculated by producers on a rate schedule by rate schedule basis in accordance with the percentages set forth in *Jack W. Grigsby*, 32 FPC 529 (1964),

[10,658]

which provide for 100 percent cash refunds for the years 1963 and thereafter, 70 percent cash refunds for the years 1961 and 1962, and 25 percent cash refunds for 1960 and prior years:

Prices for Refund Calculations

	For Deliveries Under Contracts Dated Prior to January 1, 1965	For Deliveries Under Contracts Dated From January 1, 1965 to October 1, 1968	For Deliveries Under Contracts Dated on or After October 1, 1968
Onshore	20.625¢	21.25¢	30.0¢
Offshore	19.625¢	20.25¢	30.0¢

Exhibit No. 96

In applying the above price levels, it is understood that any amount collected by a producer, even though in excess of the above prices, shall not be subject to refund to the extent such collections were pursuant to a prior settlement agreement approved by the Commission, or collections were not in excess of the price set out in a permanent certificate issued by the Commission, or such collections were not in excess of the refund floor provided in a temporary authorization applicable thereto.

(b) With respect to collections for deliveries made on or after January 10, 1971, the ceiling prices set forth in Section 3.1, as adjusted by the terms of Sections 2.3 and 3.4, shall apply to all producers for the purpose of calculating refunds.

[10,659]

For purposes of calculating refunds under Subsections (a) and (b) above, the Onshore price will be applied to Offshore gas delivered inland from the Chapman Line and to gas sold from the Disputed Zone.

7.2 Within ninety (90) days after the Effective Date, each producer shall file a refund report with the Commission setting out the amount of its refund obligation to each purchaser, calculated in accordance with the provisions hereof, including accrued interest computed to the Effective Date. Such refund reports shall be verified by the respective purchasers at the time of filing. The producer shall also within ninety (90) days from the Effective Date either (A) elect to pay its refund obligation to the appropriate purchaser together with interest thereon as heretofore prescribed by the Commission for each respective rate schedule; or (B) in the alternative, file a notice that such producer elects to discharge its refund

obligations together with accrued interest thereon other than those contemplated by Sections 7.1(b) and 8.1 by authorizing and directing the purchaser to deduct three cents (3.0¢) per Mcf from current deliveries under contracts dated prior to October 1, 1970, in the Southern Louisiana Area, during a five (5)-year period following the Effective Date until

the refund obligation, including interest, is discharged. The notice of election shall be filed with the Commission with a copy to the purchaser. If the producer fails to file such notice of election within ninety (90) days from the Effective Date, the producer shall be deemed to have elected alternative (A) above.

With respect to refund amounts reported as above and as to which producers elect alternative (A), further interest shall not accrue from the Effective Date to the date specified by the Commission for the payment in cash of such refunds; *provided, however*, after the date specified by the Commission for such cash refunds simple interest at seven percent (7%) per annum shall accrue on such refund obligations until the first day of the month in which payment is made. With respect to reported refund obligations as to which a producer has elected alternative (B), further interest shall not accrue on such amount. Notwithstanding the filing by a producer of its notice under alternative (B), such producer shall have the right to pay at any time in full its remaining refund obligation to a particular purchaser.

7.2.1 Each producer who elects to follow alternative (B) shall establish and maintain accounts showing refund obligations by rate schedule and by purchaser. On or before March 15 of each

year following the year in which such producer elected to pursue alternative (B), it shall file a report with the Commission showing the current status of such accounts, and the credits against such accounts by deductions from deliveries during the preceding calendar year, or the full discharge of the obligation. The portion of the report applicable to each purchaser shall be furnished to such purchaser at the time of filing.

7.2.2 If during the five (5)-year period following the Effective Date deliveries to a purchaser or purchasers should cease before the refund obligation has been discharged under alternative (B), the producer shall within ninety (90) days refund such remaining amounts in cash to the purchaser or purchasers.

7.2.3 If at the expiration of the five (5) years following the Effective Date there remain in the accounts maintained by a producer pursuant to Section 7.2.1 any sums not discharged by the producer, the producer shall within ninety (90) days refund such remaining amounts in cash to the purchaser or purchasers to whom the amounts were due.

[10,663]

SECTION 9. TERM.

The provisions herein contained, except for Sections 7 and 8, shall be applicable to all jurisdictional sales in the Southern Louisiana Area during a term extending for three (3) years from the Effective Date of this Settlement Proposal.

Exhibit No. 97

[10,664]

Docket No. AR69-1
EXHIBIT No. 97 (DLK-2)

EXCERPTS FROM STATEMENTS FILED IN DOCKET NO. R-389A

(1) *Major Producer Group.* A joint response was filed on behalf of major producers, including those supporting the UDC Settlement Proposal. Such joint comments showed the results of applying alternative rates of return to the 1968 costs, with the caveat that there were numerous shortcomings to the techniques used in Opinion No. 468. Two of these major shortcomings were illustrated: (1) the allocation of leasehold acquisition costs, with the impact of correction ranging from 2.13¢ per Mcf to 2.5¢ per Mcf; and (2) the disregard of the time value of money in the computation of the return on rate base. The impact on 1968 costs adjusted for both shortcomings was shown to be as follows:

Rate of Return	1968 Costs Adjusted for Lease Acquisition Allocation and Time Value of Money
12 percent	29.58¢
13 percent	31.15¢
16 percent	35.90¢

Subsequent joint reply comments filed by the Major Producer Group stated:

[10,665]

> "The newly available data show that all parties, including the producer group, had significantly underestimated the current cost of finding and producing non-associated gas."

After evaluation of such data, the preliminary FPC Staff composites of the responses to the AR69-1 questionnaire, and the drilling costs for 1969, the results showed "a range of costs from 27.61¢ to 34.01¢ per Mcf." Such range was based upon Opinion Nos. 468 and 546 costing techniques, an illustrative 13 percent rate of return with only one year for time lag, and no adjustment for the understatement of return due to the disregard of the time value of money. At a 16 percent rate of return, the costs ranged from "30.48¢ to 37.86¢ per Mcf."

(2) *Texaco Inc.* Supplemental comments of Texaco Inc. recommended certificate ceiling levels for the Southern Louisiana Area of 29¢ to 31¢ per Mcf at 15.025 psia. Such ceilings were accompanied by the following caveat (Emphasis added):

> "The Commission is cautioned, however, that even at our recommended ceiling prices no guarantee can be given as to what amount of new gas reserves will be *explored for*, developed, produced *and then committed* to the interstate market."

(3) *Humble Oil and Refining Company.* The separate response of Humble Oil & Refining Company stated that:

> "For the dual purpose of inducing expanded gas exploratory programs in the major producing areas and to attract available gas supplies to the interstate market, Humble recommends that the Commission establish as interim ceilings in this proceeding prices within the range of 26-32¢ per Mcf, exclusive of any allowance for gathering."

Further, Humble stated that the cost methods adopted in Opinion Nos. 468 and 546 were biased toward lower level

cost estimates and showed that there is not a single instance where the method or approach advocated by a producer-sponsored witness was endorsed. With respect to rate of return, Humble specifically adopted the evidence presented in Docket No. AR69-1 by Dr. Ezra Solomon showing that the appropriate rate of return applicable to a new gas cost computation was in the range of 15.3-16.2 percent. Humble further observed that:

> "The establishment of lower prices for gas on the fortuitous ground of the date of contract has operated to deny contract expectations that led to past commitments of gas reserves to the interstate market."

Humble then warned:

> "In making these recommendations, we must candidly state that no quantifiable assurance can be given that such ceiling prices will bring forth sufficient new gas reserves to meet the requirements of all of the interstate pipelines."

(4) *Phillips Petroleum Company.* In separate comments, Phillips Petroleum Company stated that ceiling prices prescribed in

Docket No. R-389A for new gas sales must be at least 10¢ per Mcf higher than previous guideline or inline prices, indicating that an increase of this magnitude is *the minimum necessary* to bring about substantially increased exploration for new gas supplies.

(5) *Tenneco Oil Company.* In supplemental comments, Tenneco Oil Company stated that:

> "Based on all evidence available it is felt that price levels of at least 30¢ per Mcf for all future

sales for all areas of the nation will be necessary to give producers the incentive needed to overcome the present supply problem and meet the future needs of both the interstate and intrastate markets."

(6) *Gulf Oil Corporation, et al.* In supplemental comments, Gulf Oil Corporation and Warren Petroleum Corporation recommended that the Commission give particular consideration to *recent changes in intrastate contract prices* and conditions of sale in the Permian Basin, Texas Gulf Coast and Southern Louisiana Areas.

(7) In the investigation of intrastate contract pricing provisions conducted by Commission Staff in connection with Docket No. R-389A, Staff found that contract prices for intrastate sales within the Southern Louisiana State taxing jurisdiction ranged up to 30¢ per Mcf. (Report of Investigating Officers, p. 11, Appendix B, September 9, 1970)

Exhibit No. 98

[10,668]

Docket No. AR69-1
Exhibit No. 78 (MLK-3)

PRODUCER COMPANY WIDE SETTLEMENTS
FPC SUSPENDED RATE INCREASES

COMPANY		DATE OF ORDER	CASH REFUNDS	ANNUAL RATE REDUCTION
Amerada Petroleum Corporation	2/	2-1-63	$ 884,000	$ 351,000
Amoco Production Company	3/	4-13-66	15,551,000	5,600,000
Atlantic Refining Company	4/	10-8-64	4,766,000 1/	3,216,000
British-American Oil Producing Co.	5/	12-28-66	625,000	260,000
Cities Service Company	6/	12-26-62	2,361,000	698,000
Gulf Oil Corporation	7/	4-25-63	3,745,000	2,378,000
Humble Oil & Refining Company	8/	7-8-64	9,779,000	3,485,000
Hunt Oil Company	9/	7-16-63	600,000 1/	Not available
Mobil Oil Corporation	10/	5-5-64	12,413,000	5,541,000
Monsanto Company	11/	1-3-67	142,000	100,0
Mound Company	12/	8-5-63	405,000	113,0
Shell Oil Company	13/	8-1-62	8,700,000 1/	5,751,0
Sinclair Oil & Gas Company	14/	7-1-63	1,157,000	670,000
Sohio Petroleum Company	15/	12-30-63	1,901,000	700,000
Sun Oil Company	16/	10-1-64	4,250,000 1/	1,400,000
Sunray DX Oil Company	17/	1-29-65	2,129,000	1,400,000
Texaco Inc.	18/	12-30-63	8,251,000	2,808,000
Texas Gulf Producing Company	19/	12-30-63	833,000	410,000
Tidewater Oil Company	20/	6-15-62	4,347,000	1,280,000
Union Producing Company	21/	12-23-64	3,400,000 1/	1,060,000

1/ Exclusive of Applicable Interest

2/ 29 FPC 204
3/ 35 FPC 502
4/ 32 FPC 933
5/ 36 FPC 1134
6/ 28 FPC 1108
7/ 29 FPC 837
8/ 32 FPC 49
9/ 30 FPC 220
10/ 31 FPC 1101
11/ 36 FPC 1159
12/ 30 FPC 433
13/ 28 FPC 257
14/ 30 FPC 5
15/ 30 FPC 1623
16/ 32 FPC 894
17/ 33 FPC 128
18/ 30 FPC 1631
19/ 30 FPC 1647
20/ 27 FPC 1267
21/ 32 FPC 1506

Southern Louisiana Area Rate Proceedings
Refund Obligations of Major Producers Through 1970 Under Opinion No. 546 Rates
(000's omitted)

Company	Total	Principal	Interest
Amerada	$ 944	$ 821	$ 123
Atlantic Richfield	8,540	7,730	810
California	42,280	31,787	10,493
Cities Service Cos.	3,352	3,010	342
Forest	4,899	3,520	1,379
General American	13,353	10,694	2,659
Getty	4,617	4,206	411
Gulf	7,501	6,868	633
Humble	24,455	22,589	1,866
Hunt Interests	7,342	6,110	1,232
Kerr-McGee	10,591	8,028	2,563
Marathon	2,025	1,767	258
Mobil	6,466	5,898	568
Pan American	8,483	7,421	1,062
Phillips	12,160	9,268	2,892
Placid	14,251	11,020	3,231
Shell	36,568	31,252	5,316
Sun & Sunray DX	7,405	6,845	560
Superior	59,602	46,906	12,696
Texaco	17,245	15,357	1,888
Union Oil of California	17,047	13,506	3,541
Union Producing	1,051	974	77
Union Texas	381	353	28

Source: Information developed from producer rate schedules on file with the Federal Power Commission projected through the year 1970 using estimated production volumes.

253 e

Exhibit No. 99

[10,669]

Docket No. AR 69-1
Exhibit No. 22 (DDK-4)

[10,669]

[10,732]

Exhibit No. 100

[10,732]

TABLE B

APPROXIMATION OF INCREASE IN VALUE OF ALREADY COMMITTED RESERVES UNDER PROPOSED SETTLEMENT TO BE REALIZED IN THE FUTURE

REMAINING RECOVERABLE GAS RESERVES COMMITTED TO INTERSTATE MARKETS AS OF 1/1/67 PER SCHS. EXHIBIT A	66,918,450,000 Mcf
ESTIMATED AVERAGE INCREASE BY LIGHT FROM TABLE C	5¢ PER Mcf
ESTIMATED INCREASE IN VALUE OF RESERVES, TO BE REALIZED IN THE FUTURE (ROUNDED)	3.3 BILLION DOLLARS

ANNUAL PRODUCTION FROM ABOVE RESERVES, 1969 PER SCHS. EXHIBIT A	4,048,918,000 Mcf
ESTIMATED AVERAGE INCREASE	5¢ PER Mcf
ESTIMATED ANNUAL INCREASE IN REVENUES TO PRODUCERS (ROUNDED)	200 MILLION DOLLARS

Exhibit No. 100

[10,733]

TABLE A

TABULATION OF PRODUCERS WHO ARE DELIVERING GAS TO CANTUA-ESPINOSA MEASURING STATION VOLUMES

PRODUCER	MCF
GULF OIL CO.	443,439,033
HUMBLE OIL & REFINING CO.	430,663,117
UNION OIL OF CALIFORNIA	338,895,605
SHELL OIL CO.	209,901,639
TEXACO INC.	192,810,655
SOU AMERICAN PET. CO.	185,660,816
SUPERIOR OIL CO.	109,455,139
MOBIL OIL CORP.	103,170,347
THE CALIFORNIA CO.	153,173,407
GETTY OIL CO.	148,871,659
ATLANTIC RICHFIELD CO.	146,945,927
GENERAL AMER. OIL CO. OF TEXAS	111,319,602
CONTINENTAL OIL CO.	99,173,137
SUN OIL CO.	95,905,975
SUB-TOTAL	3,139,663,949
ALL OTHER PRODUCERS	999,194,509
TOTAL	4,098,858,458

SOURCE: EXH. 95, SALES REPORTS ON FORM 301-C FOR 1960

[10,734]

Exhibit No. 100

[10,734]

TABLE I

Computation of Increase in Value of Reserves to be Contributed by the Federal Civil Service Retirement System to be Realized in the Future

Reserves estimated to be contributed in the future - basic target	$5,000,000,000 (est.)
Additional funds forthcoming on account of reduced benefits of settlement certificates - at least ½ of total possible	2,500,000,000
TOTAL	$7,500,000,000
Estimated average increase by eight fiscal years	8% per year
Estimated increase in value of reserves to be realized in the future (rounded)	$3 billion

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Annual Treasury fund accretion received, for this item or data per year, estimated	$[illegible]
Estimated average increase	8% per year
Estimated annual increase for reserves to people over (rounded)	$[illegible] million dollars

Exhibit No. 100

[10,736]

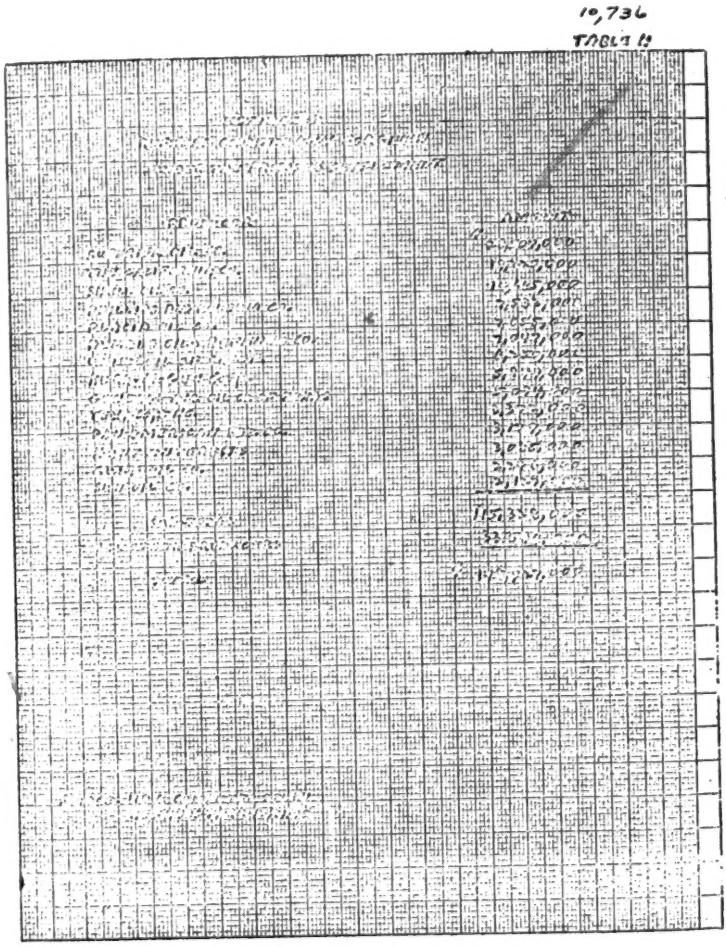

Exhibit No. 104

[10,799]

EXHIBIT No. 104
AR69-1

SOUTHERN LOUISIANA AREA RATE PROCEEDINGS

Workpapers of *B. G. Clay* in
Connection With Exhibits
90-93

SOUTHERN LOUISIANA AREA RATE PROCEEDINGS

1970 Annual Sales & Annual & Unit Revenue of Certain Large Producing Companies
Under: (a) Effective Rates; (b) Opinion 546 Rates; and, (c) USC Proposed Settlement Rates
Volumes in Mcf @ 15.025 psia and Revenues in Thousands of Dollars
Onshore Only

Line No.	Producers Column 1	1970 Annual Sales (2)	Revenue at Effective Rates Total (3)	Revenue at Effective Rates Unit (4)	Revenue @ 546 Rates Unit (5)	Revenue @ 546 Rates Below Effective Rates Amount (6)	Revenue @ 546 Rates Below Effective Rates Unit (7)	Revenue @ Proposed Settlement Rates Above Effective Price Unit (8)	Revenue @ Proposed Settlement Rates Above Effective Price Annual (9)	Revenue @ Proposed Settlement Rates Above Effective Price Unit (10)
1	Amerada	13,706	$ 2,736	20.72¢	18.62¢	$ 251	1.90¢	21.66¢	$ 136	.99¢
2	Atlantic Richfield 1/	165,412	32,302	19.53	18.37	1,909	1.16	20.20	797	.47
3	Cabot	133,162	29,020	21.79	18.82	3,955	2.97	22.21	554	.42
4	Cities Service Co.	40,863	8,003	19.58	18.72	353	.86	22.19	1,044	2.61
5	Forest	11,920	2,494	20.84	18.73	253	2.12	21.16	38	.32
6	General American	72,805	16,510	21.22	18.63	1,658	2.39	22.31	849	1.09
7	Getty	275,325	54,191	19.68	19.02	1,795	.65	22.21	3,716	1.33
8	Gulf	327,674	67,812	20.70	18.66	6,059	1.84	21.77	3,517	1.07
9	Hunt 2/	24,629	5,640	22.93	18.49	1,797	4.39	22.14	(207)	(.84)
10	Mobil 1/	37,448	7,895	21.51	18.74	964	2.87	21.25	(85)	(.26)
11	Rose-McKee	17,158	3,573	20.82	18.50	399	2.32	22.24	262	1.42
12	Shenlon	72,651	14,422	19.85	19.08	562	.77	21.70	1,360	1.85
13	Shell	187,192	36,574	19.55	18.90	1,715	.65	21.32	3,360	1.78
14	Sun Operating	40,737	7,711	19.16	18.41	308	.75	21.96	1,125	2.80
15	Texaco	43,891	9,535	22.15	19.66	1,501	3.49	21.88	(100)	(.23)
16	Phillips	43,891	9,462	22.47	18.89	1,507	3.58	22.33	(65)	(.15)
17	Placid	42,105	43,069	20.75	18.77	4,021	1.98	22.35	3,065	1.50
18	Sl-Ell	202,348	22,586	20.77	18.89	2,079	1.88	22.07	1,443	1.30
19	Sun & Sunray DX	110,596	33,755	22.97	18.60	6,420	4.37	22.39	(1,002)	(.68)
20	Superior	146,930	39,799	20.75	19.02	3,310	1.33	21.55	1,537	.40
21	Texaco	191,841	45,269	20.73	19.07	3,468	1.66	22.11	3,867	1.38
22	Union Oil	208,698	16,612	18.27	18.17	91	.10	18.33	61	.06
23	Union Texas	90,930								
24	Total Staff Reps	2,937,962	$603,996	20.56¢	18.62¢	$56,979	1.74¢	21.56¢	$39,534	1.00¢

1/ Includes Sinclair

2/ Includes H. L. Hunt, Rosata Hunt Trust, Hunt Oil Co. & Caroline Hunt Ennis & Lloyd N. Ennis

SOUTHERN LOUISIANA AREA RATE PROCEEDING

1970 Annual Sales & Annual & Unit Revenue of Certain Large Producing Companies
Under: (a) Effective Rates; (b) Opinion 546 Rates; and, (c) UNC Proposed Settlement Rates
Volumes in MMcf @ 15.025 psia and Revenues in Thousands of Dollars
(As Shown Filed)

Line No.	Producers (Column 1)	1970 Annual Sales (2)	Revenue at Effective Rates — Total (3)	Revenue at Effective Rates — Unit (4)	Revenue @ 546 Rates — Unit (5)	Revenue @ 546 Rates — Above Effective Rates — Annual (6)	Revenue @ 546 Rates — Above Effective Rates — Unit (7)	Revenue @ Proposed Settlement Rates — Unit (8)	Revenue @ Proposed Settlement Rates — Above Effective Rates — Annual (9)	Revenue @ Proposed Settlement Rates — Above Effective Rates — Unit (10)
1	Amerada	11,039	$ 2,053	18.60¢	18.52¢	$ 9	.08¢	26.00¢	$ 817	7.40¢
2	Atlantic Richfield 1/	58,711	10,033	19.50	18.00	911	1.50	21.51	671	1.71
3	Cities	38,235	15,177	19.40	17.92	1,161	1.48	21.07	1,303	1.67
4	Clinton Service Co.	43,579	8,433	19.35	17.97	604	1.38	21.90	1,110	2.55
5	Forest	17,520	3,758	19.77	18.48	51	.30	25.37	1,156	6.60
6	General American	35,390	7,046	19.50	17.12	868	2.38	20.30	363	1.00
7	Getty	44,658	9,320	19.14	15.72	449	.92	22.08	1,430	2.94
8	Gulf	182,248	35,165	19.25	17.95	2,424	1.33	20.41	2,093	1.13
9	Placid	137,575	27,850	20.25	17.96	3,143	2.29	21.37	1,967	1.12
10	Shell 2/	16,021	2,910	18.53	17.56	44	.27	18.71	77	.48
11	Pennzoil	39,535	7,441	18.91	17.46	920	2.45	21.14	462	1.23
12	Superior	4,263	847	18.33	17.55	61	1.28	23.03	200	4.20
13	Texaco	133,921	25,524	19.19	18.03	1,548	1.16	22.45	4,332	3.26
14	Tex Am Petroleum	109,319	20,290	19.41	17.84	1,662	1.57	23.68	3,772	3.61
15	Transwell	4,011	744	18.55	13.42	5	.13	24.26	329	3.71
16	Phillips	80,529	3,890	13.95	17.47	303	1.48	20.43	305	1.48
17	Placid	4,958	903	18.24	17.96	14	.28	19.05	40	.81
18	Shell	134,498	27,340	20.33	18.20	2,868	2.13	21.75	1,509	1.42
19	Shell Survey DC	3,712	700	18.85	17.27	59	1.58	22.14	122	3.28
20	Superior	52,522	10,851	20.72	17.03	1,937	3.69	21.39	354	.67
21	Texaco	96,192	18,424	19.15	18.03	1,081	1.12	19.85	665	.70
22	Union Oil	191,305	35,624	18.62	17.32	2,111	1.10	20.85	4,262	2.23
23	Union Texas	34	7	20.59	17.65	1	2.94	20.59	0	0
24	Total Staff Tape	1,775,637	$343,306	19.36¢	17.88¢	$26,228	1.48¢	21.49¢	$37,762	2.13¢

1/ Includes Sinclair

2/ Includes W. L. Hunt, Hassie Hunt Trust, Hunt Oil Co. & Caroline Hunt Lands & Lloyd B. Lands

Exhibit No. 104

[10,806]

SOUTHERN LOUISIANA AREA RATE PROCEEDINGS
Refunds Under Individual Company Settlements of Certain Large Producing Companies
1960 - 1970
(Thousands of Dollars)

Schedule 9i-2
Sheet 2 of 4

Line No.	Producers (Column 1)	1960 (2)	1961 (3)	1962 (4)	1963 (5)	1964 (6)	1965 (7)	1966 (8)	1967 (9)	1968 (10)	1969 (11)	1970 (12)	Total (13)
1	Amerada Petr.	126	252	314	26	867							1,585
2	Atlantic Richfield	1,819	2,060	2,247	1,869								8,195
3	Continental Company	273	324	231	88	14	15						3,881
4	Chicago Service Co.	854	1,265	862	34								
5	Forest Oil		32										35
6	General American				2,501	826							4,811
7	Getty Oil		120	1,292	733	153	188	31					2,518
8	Gulf Oil	227	282	1,508	2,113	1,141	314	73	31		157	98	5,943
9	Hunt Interests	33	33	375	262	11	73		369				1,024
10	Kerr-McGee			14									14
11	Shenandoah Oil		36	75	515	617	373						2,059
12	Shell Oil	2,555	489	884	1,216	2,436	1,016	320	320	159	8	32	9,611
13	Pan American Petroleum	19	339	834	791	696							2,325
14	Phillips Petroleum		346	836	15								1,197
15	Placid Oil	84	71	60									215
16	Shell Oil	337	5,761	2,453	1,021	888							10,460
17	Sun Oil	1,881	1,913	1,409	1,425	1,344	1,607	256	369	157			10,362
18	Superior Oil		1,311	1,593	1,818	92	198	250					5,262
19	Texaco Oil	410	646	196	2								1,254
20	Union Texas Petroleum	2,555		4									2,559
21	Total	8,823	15,992	20,574	15,560	9,732	4,347	1,135	343	159	8	32	75,892

Exhibit No. 104

[10,808]

SOUTHERN LOUISIANA AREA RATE PROCEEDING
Rate Revenues of Certain Large Producing Companies
Under FPC Gas Rate Schedules
Net of Individual Company Settlements
1960-1970
(Cents Per Mcf)

Schedule 91-1
Sheet 4 of 4

Line No.	Producers (Column 1)	1950 (2)	1951 (3)	1952 (4)	1953 (5)	1954 (6)	1955 (7)	1956 (8)	1957 (9)	1958 (10)	1959 (11)	1960 (12)	1961 (13)
1	Amerada Hess	19.65	18.55	19.04	18.48	19.00	19.73	20.17	20.48	20.75	20.71	20.37	19.84
2	Atlantic Richfield	18.22	18.42	17.76	18.32	17.38	18.36	18.48	18.54	19.71	19.34	19.76	19.76
3	California Company	22.22	23.43	22.17	22.37	21.73	21.36	21.32	21.18	21.23	21.09	21.37	21.33
4	Cities Service	19.17	18.23	18.66	18.96	18.97	19.18	19.11	19.13	21.38	21.34	21.21	19.25
5	Forest Oil	19.62	19.86	20.23	20.60	21.02	21.12	21.11	21.10	21.46	21.36	20.44	20.03
6	General American	17.45	17.86	19.69	19.60	19.96	20.65	20.84	21.25	21.05	20.33	20.44	19.63
7	Getty Oil	21.25	21.35	15.47	16.36	18.63	19.49	19.57	19.61	19.54	19.54	19.54	19.63
8	Gulf Oil	21.31	21.89	20.46	20.24	20.07	19.40	19.02	19.38	19.41	19.39	19.43	19.43
9	Hunt Interests	20.62	21.02	20.72	20.24	20.00	20.23	20.01	20.07	20.39	20.47	20.59	20.70
10	Ingram Corp.	21.95	22.12	20.90	19.01	20.16	20.29	20.33	21.01	21.11	22.26	21.35	21.15
11	Placid Oil	21.57	21.49	21.41	21.35	20.78	20.67	21.20	21.20	20.50	20.03	20.04	20.05
12	Shell Oil	20.18	20.43	19.96	18.61	18.76	18.90	19.55	20.44	20.53	19.42	19.63	19.61
13	Pan American Petroleum	20.37	20.32	18.91	17.86	17.94	18.27	18.66	18.92	19.18	19.42	19.63	19.70
14	Phillips	20.08	20.32	19.61	17.35	19.06	19.56	18.96	19.33	19.44	19.56	19.56	19.70
15	Phillips Petroleum	20.09	20.32	19.61	17.35	19.06	19.56	18.96	19.33	19.44	19.56	19.56	19.70
16	Placid Oil	21.09	22.01	21.74	21.96	21.33	21.54	21.38	21.18	21.13	19.13	19.47	19.45
17	Placid Oil	21.48	22.11	22.59	23.08	22.96	22.34	21.54	21.38	21.18	20.99	20.78	21.44
18	Sun Oil	22.10	22.10	19.26	17.63	18.55	19.12	20.05	21.03	21.33	21.60	21.84	22.36
19	Superior Oil	20.10	20.63	19.36	20.35	20.61	20.66	20.91	20.14	20.68	21.03	20.71	20.84
20	Texaco	20.62	21.15	21.88	21.48	20.70	20.05	21.59	22.45	22.38	22.31	22.35	21.72
21	Union Oil	18.09	19.23	19.43	19.76	20.44	19.19	19.41	19.16	20.55	20.19	20.19	19.97
22	Exxon, Texas Petroleum	19.23	19.24	18.71	19.70	19.20	19.03	19.30	19.25	19.52	19.63	19.63	19.10
23	Total	20.32	20.17	19.62	19.62	19.59	19.55	19.46	19.59	20.22	20.16	20.10	19.86

Line No.	Producers (Column 1)	1962 (14)	1963 (15)	1964 (16)	1965 (17)	1966 (18)	1967 (19)	1968 (20)	1969 (21)	1970 (22)
1	Amerada Hess	19.84	19.76	19.76	19.76	19.76	19.76	19.76	19.76	19.76
2	Atlantic Richfield	19.76	19.76	19.76	19.76	19.76	19.76	19.76	19.76	19.76
3	California Company	21.33	21.33	21.33	21.33	21.33	21.33	21.33	21.33	21.33
4	Cities Service	19.25	19.25	19.25	19.25	19.25	19.25	19.25	19.25	19.25
5	Forest Oil	20.03	20.03	20.03	20.03	20.03	20.03	20.03	20.03	20.03
6	General American	19.63	19.63	19.63	19.63	19.63	19.63	19.63	19.63	19.63
7	Getty Oil	19.63	19.63	19.63	19.63	19.63	19.63	19.63	19.63	19.63
8	Gulf Oil	19.63	19.63	19.63	19.63	19.63	19.63	19.63	19.63	19.63
9	Hunt Interests	20.70	20.70	20.70	20.70	20.70	20.70	20.70	20.70	20.70
10	Ingram Corp.	21.15	21.15	21.15	21.15	21.15	21.15	21.15	21.15	21.15
11	Placid Oil	20.05	20.05	20.05	20.05	20.05	20.05	20.05	20.05	20.05
12	Shell Oil	19.61	19.61	19.61	19.61	19.61	19.61	19.61	19.61	19.61
13	Pan American Petroleum	19.70	19.70	19.70	19.70	19.70	19.70	19.70	19.70	19.70
14	Phillips	19.70	19.70	19.70	19.70	19.70	19.70	19.70	19.70	19.70
15	Phillips Petroleum	19.45	19.45	19.45	19.45	19.45	19.45	19.45	19.45	19.45
16	Placid Oil	21.44	21.44	21.44	21.44	21.44	21.44	21.44	21.44	21.44
17	Sun Oil	22.36	22.36	22.36	22.36	22.36	22.36	22.36	22.36	22.36
18	Superior Oil	20.84	20.84	20.84	20.84	20.84	20.84	20.84	20.84	20.84
19	Texaco	21.72	21.72	21.72	21.72	21.72	21.72	21.72	21.72	21.72
20	Union Oil	19.97	19.97	19.97	19.97	19.97	19.97	19.97	19.97	19.97
21	Exxon, Texas Petroleum	19.10	19.10	19.10	19.10	19.10	19.10	19.10	19.10	19.10
22	Total	19.86	19.86	19.86	19.86	19.86	19.86	19.86	19.86	19.86

Exhibit No. 104

[10,809]

Schedule XI-3
Sheet 1 of 4

SOUTHERN LOUISIANA AREA RATE PROCEEDINGS
Refunds of Certain Large Producing Companies Under Opinion 546
Pre 1959--1960-1970
(Thousands of Dollars)

Line No.	Producers	Pre 1959 (2)	1959 (3)	1960 (4)	1961 (5)	1962 (6)	1963 (7)	1964 (8)	1965 (9)	1966 (10)	1967 (11)	1968 (12)	1969 (13)	1970 (14)	Total (15)
1	Arnada Hess	.	.	.	.	.	6	6	44	76	188	338	339	339	821
2	Atlantic Richfield	.	.	11	.	.	.	58	88	186	184	1,224	2,857	2,857	7,390
3	Cities Service Company	69	1,538	2,139	2,491	2,635	2,434	2,434	2,343	2,352	2,554	3,223	4,633	4,633	31,377
4	Forest Oil	.	.	.	.	.	.	10	113	157	334	395	1,108	1,102	3,010
5	General American	.	86	.	172	301	447	526	676	451	330	365	177	177	3,550
6	Getty Oil	.	58	.	221	425	506	579	1,055	1,055	1,473	1,484	1,773	1,773	10,505
7	Gulf Oil	.	.	.	.	.	.	.	105	105	113	764	1,708	1,708	4,503
8	Mobil Oil	.	.	.	.	.	.	.	.	.	852	2,394	2,801	2,801	22,349
9	Pan Eastern	.	.	.	.	.	.	.	.	.	.	1,054	1,365	1,365	4,110
10	Petrolane	8	68	139	135	147	174	183	471	686	681	776	1,453	1,453	6,019
11	Sheridan Oil	337	473	391	388	385	334	471	686	132	207	333	467	467	1,141
12	Shell Oil	.	.	.	.	.	.	.	33	33	333	333	2,295	2,295	7,621
13	Pan American Petroleum	121	.	134	138	77	123	117	9	96	334	333	424	424	934
14	Phillips Petroleum	438	562	491	563	563	549	553	660	1	568	880	1,776	1,776	9,269
15	Plastic Oil	133	333	451	674	787	834	795	1,000	1,004	1,559	1,711	3,228	3,228	11,000
16	Shell Oil	.	.	.	.	.	.	.	2,109	4,536	4,672	5,711	7,228	7,228	31,252
17	Sun Oil	69	1,290	1,774	2,017	2,655	3,065	2,941	3,538	3,100	3,099	5,347	8,570	8,570	44,964
18	Superior Oil	.	.	.	.	.	.	11	131	118	2,099	3,347	4,249	4,249	13,357
19	Texaco	35	114	600	674	846	1,021	1,050	1,058	1,110	1	43	2,469	2,469	13,365
20	Union Texas Petroleum	.	.	.	.	.	.	.	.	.	.	.	155	155	353
21	Total	1,827	4,791	6,738	8,529	9,310	9,956	10,378	16,605	21,446	26,522	48,533	63,533	255,936

Exhibit No. 104

[10,810]

Schedule 91-3
Sheet 2 of 4

SOUTHERN LOUISIANA AREA RATE PROCEEDINGS
Interest on Refunds of Certain Large Producing Companies Under Opinion 546
Pre-1960, 1960-1970
(Thousands of Dollars)

Line No.	Producers — Column 1	Pre-1960 (2)	1960 (3)	1961 (4)	1962 (5)	1963 (6)	1964 (7)	1965 (8)	1966 (9)	1967 (10)	1968 (11)	1969 (12)	1970 (13)	Total (14)
1	Amerada Hess	*	*	7	*	9	26	37	35	36	22	22	*	135
2	Atlantic Richfield	*	*	*	*	*	*	34	32	48	203	238	168	810
3	California Company	595	1,206	1,434	1,482	1,273	1,102	827	751	696	350	306	144	10,469
4	Cities Service	*	*	*	*	*	*	43	149	21	43	115	39	332
5	Forest Oil	7	64	117	226	244	239	163	162	261	294	184	85	1,789
6	General American	*	43	148	264	247	262	403	272	237	266	184	85	1,810
7	Getty Oil	*	*	*	*	*	*	41	32	34	207	213	85	611
8	Pacific Oil	*	*	*	*	*	*	*	*	*	210	1,000	238	1,448
9	Phillips Petroleum	265	349	262	348	310	271	361	216	207	210	144	67	2,905
10	Pure Interstate	*	*	*	*	*	*	*	43	71	231	239	132	716
11	Reynolds	97	91	83	46	64	53	37	30	42	154	239	85	1,062
12	Shell Oil	*	*	*	*	*	*	*	*	*	138	288	85	368
13	Sun American Petroleum	*	*	*	*	*	*	*	*	44	155	239	85	77
14	Phillips Petroleum	343	413	327	335	306	335	316	195	133	231	144	68	3,607
15	Placid Oil	100	339	395	420	434	335	809	1,330	1,141	1,275	1,144	532	8,331
16	Shell Oil	*	*	*	*	*	*	*	*	*	1,210	1,144	532	2,886
17	Skelly Oil	55	948	1,315	1,225	1,501	1,405	1,132	1,115	1,251	1,064	892	383	12,686
18	Standard Oil	*	*	*	*	2	5	7	34	333	495	300	144	1,318
19	Texaco	24	123	406	402	444	464	405	333	371	305	273	91	3,561
20	Union Texas Petroleum	*	*	*	*	*	*	*	*	*	*	*	*	*
24	Total	1,459	3,522	4,487	5,221	4,806	4,521	4,774	3,223	3,238	6,360	6,649	3,224	54,638

SOUTHERN LOUISIANA AREA RATE PROCEEDINGS
Unit Revenues of Certain Large Producing Companies Under Opinion 546
1960-1970
(Cents Per Mcf)

Line No.	Producers Column 1	1960 (2)	1961 (3)	1962 (4)	1963 (5)	1964 (6)	1965 (7)	1966 (8)	1967 (9)	1968 (10)	1969 (11)	1970 (12)	Total (13)
1	Accrede Hess	19.65	18.55	19.94	18.56	18.94	19.33	19.51	19.84	19.75	19.19	18.98	19.30
2	Atlantic Richfield	18.22	18.81	17.96	18.52	17.34	18.29	18.61	18.46	18.96	18.19	18.49	18.35
3	California Company	19.87	19.75	19.60	19.72	19.34	19.34	19.55	19.45	19.23	18.39	18.94	19.27
4	Cities Service	19.17	18.23	16.66	18.96	18.95	18.89	18.82	18.95	21.09	18.05	18.16	18.75
5	Forest Oil	18.49	18.50	18.50	18.51	18.50	18.50	18.50	18.50	18.51	18.51	19.36	18.60
6	General American	15.98	16.96	18.12	17.99	18.42	18.25	18.53	19.14	19.15	19.06	18.92	18.69
7	Getty Oil	21.27	21.36	15.47	14.34	18.42	19.38	19.49	19.53	19.77	18.47	18.60	18.70
8	Gulf Oil	21.31	21.80	20.49	19.25	19.40	19.00	19.24	19.12	18.75	18.89	18.89	19.21
9	Humble Oil	20.62	21.02	20.72	20.24	20.07	18.73	20.01	20.06	19.65	18.73	18.92	19.50
10	Mobil Interests	21.68	21.62	20.40	18.46	19.55	19.60	19.79	19.22	18.78	19.43	18.25	19.55
11	Pure-McGee	20.26	20.21	19.77	19.84	19.78	19.51	20.45	19.57	19.01	18.06	18.32	19.34
12	Pure Oil	20.18	20.42	19.94	18.61	18.78	19.27	18.74	18.97	18.80	18.76	17.98	18.58
13	Rabil Oil	20.11	19.44	18.91	17.89	17.94	18.27	18.57	18.78	18.60	18.22	18.55	18.53
14	Van American Petroleum	20.29	20.63	20.33	20.00	19.52	19.49	18.92	19.23	19.11	18.55	18.55	19.37
15	Pennzoil	20.0-	19.61	17.55	17.86	17.37	17.51	17.59	17.74	17.52	18.33	18.89	18.18
16	Phillips Petroleum	20.1	20.79	20.40	20.73	20.69	20.45	20.39	20.16	19.72	18.28	18.28	19.50
17	Placid Oil	19.83	19.58	19.51	19.44	19.60	15.64	19.61	19.54	19.21	18.74	18.52	19.26
18	Shell Oil	22.10	19.26	17.43	18.95	19.12	19.02	19.09	19.38	18.84	18.38	18.47	18.97
19	Sun Oil	23.10	20.63	19.36	20.35	20.81	20.66	20.31	20.13	20.07	19.68	18.68	19.89
20	Superior Oil	19.53	20.73	20.12	19.76	18.99	19.01	19.69	19.81	19.38	18.25	18.30	19.30
21	Texaco	20.62	19.41	19.63	19.97	20.61	19.18	19.29	18.11	19.76	18.60	18.60	19.09
22	Union Oil	17.93	18.92	19.12	19.39	19.30	19.01	18.91	18.88	19.00	18.98	18.98	18.96
23	Union Texas Petroleum	18.71	18.71	18.71	18.70	18.70	18.71	18.70	18.71	18.72	19.04	19.35	18.72
24	Total	19.97	19.72	19.10	19.15	19.14	19.04	19.25	19.25	19.18	18.58	18.69	19.08

Schedule 5-3
Sheet 4 of 5

SOUTHERN LOUISIANA AREA RATE PROCEEDINGS
Refunds of Certain Large Producing Companies Under Settlement Proposal
For 1960 - 1970
(Thousands of Dollars)

Line No.	Producers Column 1	Pre 1960 (2)	1960 (3)	1961 (4)	1962 (5)	1963 (6)	1964 (7)	1965 (8)	1966 (9)	1967 (10)	1968 (11)	1969 (12)	1970 (13)	Total (14)
1	Amerada Petr	-	-	-	-	1	1	4	11	14	26	69	69	195
2	Atlantic Richfield	-	-	9	-	-	-	-	1	4	810	873	873	2,570
3	California Company	382	696	1,212	1,458	1,461	1,428	918	987	1,063	1,165	1,676	1,676	13,999
4	Cities Service	-	-	-	-	-	-	-	-	-	82	335	335	752
5	Forest Oil	6	5	3	2	15	80	4	2	-	20	54	54	243
6	General American	-	59	145	284	257	537	390	409	484	509	541	541	3,967
7	Getty Oil	-	-	-	-	-	-	-	-	-	92	528	528	1,148
8	Gulf Oil	-	-	-	-	-	-	-	-	-	111	827	827	1,865
9	Humble Oil	-	-	-	-	-	-	-	-	-	755	2,940	2,940	6,635
10	Texas Interests	6	33	90	84	100	118	98	514	377	414	410	410	2,674
11	Kerr-McGee	210	343	275	421	416	393	317	335	334	361	445	445	4,295
12	Petroleum Oil	-	-	-	-	-	-	12	69	24	95	143	143	536
13	Mobil Oil	-	-	-	-	-	-	-	-	-	166	703	703	1,572
14	Pan American Petroleum	99	105	105	64	100	96	61	57	44	234	839	839	2,641
15	Pennzoil	-	-	-	-	-	-	-	-	-	23	129	129	281
16	Phillips Petroleum	326	442	395	452	452	465	428	487	446	433	543	543	5,412
17	Placid Oil	-	177	300	452	562	581	392	486	547	759	516	516	5,289
18	Shell Oil	-	-	-	-	-	-	1,056	2,153	2,319	2,389	2,706	2,206	12,329
19	Sun Oil	-	-	-	-	-	-	-	-	-	703	901	901	2,005
20	Superior Oil	34	727	1,145	1,847	1,842	1,991	1,474	1,822	2,814	2,702	2,613	2,613	21,644
21	Texaco	-	-	-	3	4	8	3	2	5	254	1,450	1,450	3,179
22	Union Oil	14	69	313	544	584	468	370	373	384	530	797	797	4,845
23	Union Texas Petroleum	-	-	-	-	-	-	-	-	-	11	47	47	152
24	Total	1,075	2,854	3,992	5,431	5,034	5,966	5,529	7,508	8,889	11,635	19,363	19,363	97,279

Exhibit 104
Sheet 1 of 1

Exhibit No. 104

[10,814]

EXHIBIT INTERESTS AND GIVE ALLOCATION
Interest on Refunds of Certain Large Producers Under the Settlement Agreement
Per. 1959, 1960, 1961, 1962, 1963, 1964, 1965, 1966, 1967, 1968, 1969, 1970, Total
(Thousands of Dollars)

Line No.	Producer (Column F)	Per. 1959 (2)	1960 (3)	1961 (4)	1962 (5)	1963 (6)	1964 (7)	1965 (8)	1966 (9)	1967 (10)	1968 (11)	1969 (12)	1970 (13)	Total (14)
1	Aberdeen Gas	-	-	6	-	1	-	2	3	1	5	7	2	29
2	Atlantic Richfield	-	-	6	-	-	-	-	-	-	26	89	31	151
3	California Company	306	659	606	867	369	615	304	312	255	202	158	52	3,306
4	Cities Service	-	-	-	-	-	-	-	-	-	10	35	12	57
5	Colorado Oil & Gas	-	4	9	-	9	35	2	1	-	5	9	4	68
6	Continental Oil	-	35	93	160	150	152	150	179	116	67	53	18	1,161
7	Gulf Oil	-	-	-	-	-	-	-	-	-	11	84	29	124
8	Kerr-McGee Oil	-	-	-	-	-	-	-	-	-	169	304	103	578
9	Kiantone Petroleum	4	35	65	33	53	59	39	103	69	70	45	16	513
10	Mobil Oil	107	213	163	230	220	178	151	164	88	46	45	16	1,410
11	Pennzoil	-	-	-	-	-	-	5	28	16	16	15	5	80
12	Phillips Petroleum	39	76	70	50	50	45	23	18	11	24	23	4	330
13	Pure Oil	-	-	-	-	-	-	-	-	-	13	5	3	21
14	Pennzoil	261	326	262	258	210	210	165	155	110	74	52	19	2,153
15	Phillips Petroleum	-	130	260	258	210	205	151	155	106	135	53	18	1,502
16	Placid Oil	-	-	-	-	-	-	407	579	556	455	323	112	2,504
17	Shell Oil	-	-	-	-	-	-	-	-	-	221	92	32	345
18	Sun Oil	37	555	222	1,111	667	593	-	575	459	401	276	95	6,399
19	Superior Oil	-	-	-	-	9	15	-	-	-	35	151	53	263
20	Texaco	15	51	204	222	222	212	149	117	95	93	64	24	1,459
21	Union Oil	-	-	-	-	-	-	-	-	-	-	-	-	-
22	United States Petroleum	-	-	-	-	-	-	-	-	-	-	-	-	-
23	Total	859	2,009	2,647	3,222	2,960	2,899	2,331	2,331	2,170	1,855	1,602	625	25,511

Exhibit No. 104

[10,818]

SOUTHERN LOUISIANA AREA RATE PROCEEDINGS
Percent of Tax Reimbursement Claimed by Producers
(a) Opinion 546 Rates and (b) Proposed Settlement Rates
(000's omitted)

Line No.	Company Column 1	Opinion 546 Refund (2)		Interest (4)		Settlement Refund (5)		Interest (7)	
		Total (3)				Total (6)			
1	Amerada	$ 944	$ 831	$ 113		$ 215	$ 195	$ 20	
2	Atlantic Richfield	8,540	7,730	810		2,111	1,980	131	
3	California Company	42,280	31,787	10,493		15,295	13,999	1,296	
4	Cities Service Co.	3,353	3,010	343		809	752	57	
5	Forest	4,899	3,520	1,379		311	253	58	
6	General American	13,333	10,674	2,659		5,138	3,967	1,161	
7	Gulf	4,143	3,706	437		1,293	1,148	84	
8	Humble	7,501	6,604	897		1,760	1,622	138	
9	Hunt Interests	24,455	22,589	1,866		3,153	2,835	318	
10	Kerr-McGee	7,352	4,110	1,232		5,001	4,674	327	
11	Marathon	10,591	8,028	2,563		5,978	4,925	1,053	
12	Ohio	2,003	1,742	261		616	536	80	
13	Pan American	8,648	7,838	810		1,682	1,372	310	
14	Pennzoil	1,081	974	77		1,088	1,001	87	
15	Phillips	12,160	9,268	2,892		7,595	5,413	2,182	
16	Placid	14,251	11,000	3,251		7,091	5,286	1,805	
17	Shell	36,568	31,252	5,316		14,717	12,559	2,158	
18	Sun Oil Co.	9,602	7,345	2,257		2,158	2,005	153	
19	Superior	59,402	44,606	14,796		25,433	21,444	3,989	
20	Texaco	17,245	13,337	3,908		3,633	3,377	256	
21	Union Oil of California	13,067	11,506	1,561		6,291	4,845	1,446	
22	Union Texas	381	355	26		112	105	7	
23	Total Sample (82.5%)	$310,559	$255,900	$54,658		$123,119	$ 97,578	$25,540	
24	Grand Total 1/	$376,528	$310,213	$66,315		$149,220	$117,902	$31,318	

	Producers	Offshore
All Sales		
Cont. Rate Pre 10/1/69	18.5%	17.0%
Cont. Rate 12/1/61 - 10/1/68	19.3	18.0
Cont. Rate Post 10/1/68	20.0	18.5

	Producers	Offshore
Sales Prior to 1/1/61	20.625%	19.25%
Sales 1/1/61 - 1/1/71	21.25	20.25
Sales 10/1/68 - 1/1/71	2/	2/

1/ Factored up on the basis that sales for the sample companies accounted for 82.5% of total sales in 1968.

*Refunds at 20.5% of Opinion 546 Refunds

Schedule 91-3
Sheet 2 of 2

Exhibit No. 106

[10,823]

EXHIBIT No. 106 (CSG-6)
Witness: Celia Star Gody

UNITED STATES OF AMERICA
FEDERAL POWER COMMISSION

Docket Nos. AR61-2, *et al.*
AR69-1

IN THE MATTER OF

AREA RATE PROCEEDINGS
(SOUTHERN LOUISIANA AREA)

RANGE OF COMPANY UNIT REVENUES UNDER ALTERNATIVE RATE DESIGNS

Foster Associates, Inc.
Washington, D. C.

March 1971

[10,826]

Exhibit No. 106

[10,826]

270 e

RANGE OF COMPANY AVERAGE UNIT REVENUES
UNDER ALTERNATIVE RATE DESIGNS
(Median and Quartiles Determined by Volume)

	Opinion No. 546 Rates	UDC Settlement Proposal	Single Ceiling Price of: 22.00 Cents	24.00 Cents	26.00 Cents	28.00 Cents	30.00 Cents
Lowest Company	13.88	14.34	14.34	14.34	14.34	14.34	14.34
1st Quartile	18.42	21.00	20.88	21.66	21.99	22.10	22.22
Median	18.67	21.48	21.37	22.21	22.66	22.97	23.09
3rd Quartile	18.84	21.96	21.63	22.86	23.76	24.12	24.36
Highest Company	20.30	22.58	22.00	24.00	26.00	28.00	30.00
Weighted Average Unit Revenue, 100 Companies	18.63	21.38	21.15	22.18	22.84	23.21	23.33

Note: For each assumed rate design, companies are arrayed by average unit revenue from lowest to highest.
The "1st Quartile" is the average revenue below which companies with one-fourth of the total volume fall.
The "Median" is the average revenue above and below which companies with one-half of the total volume fall.
The "3rd Quartile" is the average revenue below which companies with three-fourths of the total volume fall.

Schedule 1

RANGE OF COMPANY AVERAGE UNIT REVENUES
UNDER ALTERNATIVE RATE DESIGNS
(Median and Quartiles Determined by Number of Companies)

	Opinion No. 546 Rates	UDC Settlement Proposal	Single Ceiling Price of: 22.00 Cents	24.00 Cents	26.00 Cents	28.00 Cents	30.00 Cents
Lowest Company	13.88	14.34	14.34	14.34	14.34	14.34	14.34
1st Quartile	18.41	20.81	20.74	21.13	21.29	21.46	21.47
Median	18.62	21.66	21.42	22.43	22.74	22.89	22.99
3rd Quartile	19.15	22.36	21.98	23.50	24.46	24.58	24.74
Highest Company	20.30	22.58	22.00	24.00	26.00	28.00	30.00
Weighted Average Unit Revenue, 100 Companies	18.63	21.38	21.15	22.18	22.84	23.21	23.33

Note: For each assumed rate design, companies are arrayed by average unit revenue from lowest to highest.
The "1st Quartile" is the average revenue below which one-fourth of the companies fall.
The "Median" is the average revenue above and below which one-half of the companies fall.
The "3rd Quartile" is the average revenue below which three-fourths of the companies fall.

Exhibit No. 107

[10,831]

SOUTHERN LOUISIANA AREA RATE PROCEEDING
Annual Sales of Certain Large Producing Companies
Under FPC Gas Rate Schedules
1960-1970
Mcf @ 15.025 psia

Schedule 1

Line No.	Producer (Group I)	1950 (2)	1951 (3)	1952 (4)	1953 (5)	1954 (6)	1955 (7)	1956 (8)	1957 (9)	1958 (10)	1959 (11)	1970 (12)	Total (13)
1	Amerada Hess	6,169	6,921	8,489	10,398	10,806	11,007	11,115	10,896	12,878	15,189	15,434	128,631
2	Atlantic Richfield	107,485	116,977	122,537	143,244	134,138	134,685	147,350	150,528	205,087	211,914	216,344	1,690,489
3	California Company	69,665	86,451	97,077	93,144	102,048	99,173	103,781	153,417	140,824	138,314	200,748	1,284,442
4	Cities Service	43,052	37,704	33,078	44,524	58,304	80,028	92,651	96,692	97,154	83,723	108,842	697,749
5	Coastal States	4,041	24,091	28,034	23,218	27,332	26,207	27,296	11,700	10,216	6,854	19,742	171,340
6	Consol. American	3,944	26,413	28,357	31,334	34,739	43,844	51,193	19,317	15,044	106,405	100,677	360,883
7	Getty Oil	53,316	85,629	83,844	82,844	81,739	91,855	91,330	134,470	145,021	115,645	124,659	1,135,993
8	Gulf Oil	44,187	66,744	83,324	117,531	141,141	207,370	211,463	334,078	435,463	435,827	484,827	2,564,822
9	Humble Oil	43,654	75,963	106,987	147,382	184,110	293,812	334,089	393,231	435,463	533,291	498,827	3,146,819
10	Kerr Interests	27,086	25,430	24,978	26,770	28,488	26,596	44,134	47,434	45,001	40,544	44,872	381,333
11	Kerr-McGee	36,564	30,817	33,854	38,153	45,021	49,306	65,012	60,326	65,010	73,076	82,236	561,387
12	Mercantile Oil	14,252	45,238	34,033	31,033	20,843	15,451	16,423	30,544	30,391	21,317	30,732	190,396
13	Mobil Oil	130,000	167,049	164,324	192,583	202,135	184,660	195,160	232,795	191,454	191,454	214,332	1,975,923
14	Pan American Petroleum	18,782	18,101	19,906	45,641	45,908	52,911	59,912	53,748	57,953	70,806	73,804	511,511
15	Pennzoil	146,854	43,288	43,886	45,641	45,908	45,828	53,748	55,721	57,953	70,806	73,804	627,941
16	Phillips Petroleum	15,789	17,832	22,046	22,870	24,784	25,704	37,706	40,413	45,445	51,314	49,523	351,327
17	Placid Oil	114,254	146,214	183,534	205,633	233,447	260,375	217,407	40,117	284,902	334,971	372,498	2,615,262
18	Pure Oil	14,571	18,817	23,854	28,153	30,333	29,490	29,641	34,347	107,830	142,964	112,544	572,545
19	Superior Oil	120,991	124,723	145,593	151,533	170,333	179,490	79,641	34,347	107,830	142,964	112,544	1,370,019
20	Texaco	87,505	74,093	81,657	84,377	101,320	119,238	189,521	198,474	237,176	215,388	220,332	1,609,111
21	Union Oil	173,939	194,448	217,583	243,296	258,173	273,830	287,518	304,381	327,603	448,782	402,782	3,008,335
22	Wise Texas Petroleum	89,220	93,286	72,400	83,176	89,208	92,418	68,270	91,452	90,810	87,297	74,275	951,822
23	Total	1,370,610	1,496,282	1,728,810	1,916,713	2,109,564	2,353,340	2,755,780	3,106,003	3,538,446	4,032,339	4,275,811	28,676,552

Sources B. G. Clay work paper, denoted as Schedule 91-1; underlying Exhibit No. 91.

Exhibit No. 107

Schedule 2

SOUTHERN LOUISIANA AREA RATE PROCEEDINGS
Revenues of Certain Large Producing Companies Under FPC Gas Rate Schedules
Before Refunds to Individual Company Settlements
1960 - 1970
(Thousands of Dollars)

Line No.	Producers (Column 1)	1960 (2)	1961 (3)	1962 (4)	1963 (5)	1964 (6)	1965 (7)	1966 (8)	1967 (9)	1968 (10)	1969 (11)	1970 (12)	Total (13)
1	Amerada Hess	1,338	1,536	2,089	1,972	2,053	2,172	2,343	2,700	2,672	3,127	3,349	25,350
2	Atlantic Richfield	21,519	23,673	24,055	28,811	27,998	28,247	34,389	35,364	40,432	41,411	44,544	360,643
3	California Company	15,739	18,373	21,789	21,277	22,168	21,326	30,495	32,402	34,150	37,600	44,178	299,508
4	Cities Service Gas	8,914	8,239	6,835	8,435	9,102	9,728	10,290	10,875	14,557	16,578	20,317	123,764
5	Forest Oil	1,494	2,307	4,443	4,598	4,599	5,845	5,443	2,480	2,156	1,446	4,041	35,258
6	General American	692	4,455	5,583	6,119	7,611	9,058	10,688	14,634	18,008	22,859	20,823	119,878
7	Getty Oil	11,365	13,033	11,962	13,118	16,443	18,530	24,171	26,819	28,579	31,356	35,690	228,866
8	Gulf Oil	9,414	23,363	18,779	23,621	27,332	40,492	53,697	69,105	84,044	85,025	91,292	518,171
9	Humble Oil	13,351	16,543	24,181	32,022	38,990	53,181	66,878	78,932	89,462	113,441	125,026	651,349
10	Hunt Interests	5,974	5,459	5,596	5,339	5,747	3,400	9,411	10,007	9,394	9,184	9,335	81,537
11	Kerr-McGee	7,779	6,619	7,691	8,271	9,456	10,146	13,782	12,587	13,133	14,435	14,179	120,338
12	Marathon Oil	2,104	1,936	2,353	2,778	3,918	3,487	5,642	4,298	4,184	4,595	4,195	37,797
13	Mobil Oil	9,313	9,639	11,054	16,751	23,562	31,528	38,674	25,698	31,651	37,373	42,044	277,287
14	Pan American Petroleum	24,678	30,648	34,424	40,887	42,352	38,087	37,421	41,124	45,637	53,141	53,141 1/	441,660
15	Pennzoil	3,771	3,895	4,240	4,683	5,693	4,363	5,243	5,996	6,988	10,429	11,371 1/	66,672
16	Phillips Petroleum	10,360	8,870	9,126	9,996	10,068	9,882	11,556	11,799	12,237	14,718	14,718 1/	123,330
17	Placid Oil	3,483	4,014	5,044	5,278	5,687	5,844	8,033	8,984	10,289	11,346	10,856	78,459
18	Shell Oil	35,670	37,872	35,967	38,604	40,803	41,211	45,724	51,309	61,342	72,462	76,027	536,924
19	Sun Oil	8,611	8,898	10,884	11,543	13,525	15,264	16,215	16,988	22,564	29,660	29,660 1/	187,212
20	Superior Oil	25,948	28,154	27,543	37,345	38,935	38,419	40,474	43,411	44,697	47,078	46,163	420,105
21	Texaco	23,929	25,724	27,616	29,112	30,963	27,509	29,297	34,276	37,272	40,225	40,225 1/	355,139
22	Union Oil	31,872	37,865	42,482	46,442	52,264	53,103	55,430	58,381	63,952	73,062	73,062 1/	607,115
23	Yukon Texas	10,833	13,105	13,203	16,736	16,368	16,815	16,065	16,666	16,413	16,829	15,049	179,787
24	Total	288,409	317,755	359,696	403,642	438,725	472,349	547,863	618,952	715,563	812,825	862,378	5,838,355
25	Unit Revenue	20.90	21.24	20.81	20.41	20.04	19.74	19.88	19.84	20.23	20.18	20.22	

1/ 1971 Revenues not reported. 1969 Volume used.

Source: B. G. Clay work paper, denoted as Schedule 91-2, Sheet 1 of 4, underlying Exhibit No. 91.

Exhibit No. 107

[10,833]

Schedule 3

SOUTHERN LOUISIANA AREA RATE PROCEEDING
Refunds Under Individual Company Settlements of
Certain Large Producing Companies
1960 - 1970
(Thousands of Dollars)

Line No.	Producer (Column 1)	1960 (1)	1961 (2)	1962 (3)	1963 (4)	1964 (5)	1965 (6)	1966 (7)	1967 (8)	1968 (9)	1969 (10)	1970 (11)	Total (12)
1	Amerada Hess	224	232	316	36	67	...	...	...	...	...	...	875
2	Atlantic Richfield	1,919	2,040	2,257	1,643	1,134	11	...	...	...	...	...	8,904
3	California Company	223	224	271	84	14	...	11	...	...	...	...	826
4	Cities Service Co.	854	1,265	842	34	...	...	...	...	...	...	...	3,001
5	Forest Oil	...	21	...	...	...	...	...	...	...	...	...	21
6	General American	1,343	...	2,343	1,901	626	...	...	...	...	...	...	6,813
7	Getty Oil	1,178	1,238	1,178	237	151	...	158	...	...	...	...	4,943
8	Gulf Oil	1,178	1,238	1,178	2,113	1,141	11	158	11	...	...	...	6,963
9	Humble Oil	237	253	237	252	11	11	11	11	...	...	...	713
10	Hunt Interests	237	253	237	...	...	...	...	...	...	...	...	727
11	Kerr-McGee	...	...	...	...	...	...	...	...	...	...	...	36
12	Mobil Oil	1,178	1,238	1,178	1,238	637	11	158	11	...	...	...	5,650
13	Pan American Petroleum	1,178	1,238	1,178	1,238	1,141	11	158	11	...	...	...	6,213
14	Pennzoil	237	253	237	252	11	11	11	11	...	...	...	1,013
15	Phillips Petroleum	1,178	1,238	1,178	1,238	637	11	158	11	...	...	...	5,650
16	Placid Oil	237	253	237	252	11	11	11	11	...	...	...	1,013
17	Shell Oil	1,178	1,238	1,178	1,238	637	11	158	11	...	...	...	5,650
18	Sun Oil	237	253	237	252	11	11	11	11	...	...	...	1,013
19	Superior Oil	1,178	1,238	1,178	1,238	637	11	158	11	...	...	...	5,650
20	Texaco	1,178	1,238	1,178	1,238	637	11	158	11	...	...	...	5,650
21	Union Oil	237	253	237	252	11	11	11	11	...	...	...	1,013
22	Unio Texas Petroleum	1,178	1,238	1,178	1,238	637	11	158	11	...	...	...	5,650
23	Total	6,623	15,971	16,576	15,560	8,732	4,361	1,105	243	159	2	...	79,188

Source: B. G. Clay, work paper, denoted as Schedule 91-2, Sheet 2 of 4, underlying Exhibit No. 91.

SOUTHERN LOUISIANA AREA RATE PROCEEDINGS
Revenues of Certain Large Producing Companies Under FPC Gas Rate Schedules
Net of Individual Company Settlements
1960-1970
(Thousands of Dollars)

Line No.	Producers Column 1	1960 (2)	1961 (3)	1962 (4)	1963 (5)	1964 (6)	1965 (7)	1966 (8)	1967 (9)	1968 (10)	1969 (11)	1970 (12)	Total (13)
1	Amerada Hess	1,212	1,284	1,775	1,836	2,053	2,122	2,243	2,700	2,672	3,127	3,358	24,522
2	Atlantic Richfield	19,620	21,635	23,806	26,662	27,131	34,247	34,589	35,344	40,432	41,412	44,346	351,225
3	California Company	15,466	18,068	21,518	21,188	22,168	21,324	30,493	32,401	34,150	37,938	44,178	298,351
4	Cities Service	8,068	6,576	9,977	8,251	9,178	9,716	10,290	10,875	14,557	16,578	20,217	120,743
5	Forest Oil	1,496	2,597	4,465	4,588	4,349	3,845	3,645	2,680	2,154	1,446	4,343	35,368
6	General American	659	4,373	5,582	6,119	7,611	9,058	10,688	14,834	18,008	22,039	20,823	119,044
7	Getty Oil	11,395	11,033	9,377	11,617	15,619	18,530	24,171	26,619	28,379	31,334	35,490	223,974
8	Gulf Oil	9,416	13,243	17,687	22,884	27,127	40,324	52,328	69,100	86,044	85,025	91,222	515,536
9	Humble Oil	13,124	15,782	22,283	29,909	36,948	53,150	66,839	78,921	89,462	113,461	125,026	645,896
10	Hunt Interests	3,938	5,464	5,231	5,973	5,562	5,394	9,410	10,077	9,504	9,184	8,334	80,469
11	Kerr-McGee	2,779	6,619	7,427	8,271	9,445	20,673	13,782	12,287	13,133	14,452	10,520	120,138
12	Marathon Oil	2,994	1,900	2,918	2,779	3,914	3,167	3,642	4,208	4,184	4,365	4,195	37,708
13	Mobil Oil	9,354	9,083	10,235	13,174	15,313	14,935	18,474	25,692	31,051	37,375	43,066	226,946
14	Pan American Petroleum	26,479	30,349	33,440	38,629	39,374	36,071	37,091	41,123	43,555	53,139	53,141	433,011
15	Pennzoil	3,771	3,349	5,434	5,894	3,792	4,343	5,265	5,996	6,988	10,429	14,371	68,833
16	Phillips Petroleum	19,321	8,867	9,128	9,981	10,046	9,822	11,566	11,799	12,227	14,718	14,718	121,191
17	Placid Oil	3,598	3,443	3,894	5,278	5,687	5,844	8,003	8,994	10,289	11,346	10,846	78,614
18	Shell Oil	35,656	32,131	32,234	38,694	40,823	41,211	45,774	51,709	61,342	72,462	76,097	527,513
19	Sun Oil	8,540	8,697	9,417	10,872	14,637	15,264	16,215	16,985	22,564	29,660	29,609	182,224
20	Superior Oil	26,915	27,706	34,234	35,720	37,209	36,918	40,218	43,411	44,697	47,078	44,183	419,683
21	Texaco	13,920	16,379	16,023	17,294	20,691	22,311	29,097	38,067	37,115	40,223	40,225	341,347
22	Union Oil	31,462	37,399	42,286	48,440	52,264	53,103	53,430	58,581	63,952	79,062	79,062	601,041
23	Union Texas Petroleum	16,279	17,109	23,199	16,721	16,244	16,825	16,065	16,682	16,638	16,979	15,068	177,192
24	Total	280,386	301,763	339,130	387,982	428,973	447,967	546,668	618,709	715,404	812,823	862,770	5,762,473

Source: B. G. Clay work paper, denoted as Schedule 91-2, Sheet 3 of 4, underlying Exhibit No. 91.

Exhibit No. 107

SOUTHERN LOUISIANA AREA RATE PROCEEDING
Unit Revenues of Certain Large Producing Companies
Under FPC Gas Rate Schedules
Net of Individual Company Settlements
1960-1970
(Cents Per Mcf)

Schedule 5

Line No.	Producers (Column 1)	1960 (2)	1961 (3)	1962 (4)	1963 (5)	1964 (6)	1965 (7)	1966 (8)	1967 (9)	1968 (10)	1969 (11)	1970 (12)	Total (13)
1	Amerada Hess	19.45	18.55	19.96	18.62	19.00	19.73	20.17	20.62	20.79	20.71	20.37	19.96
2	Atlantic Richfield	18.22	18.82	17.96	18.58	17.38	16.34	16.46	18.56	19.71	19.34	19.70	18.76
3	California Company	22.22	22.43	22.17	22.27	21.72	21.51	21.21	21.12	21.23	21.09	21.27	21.52
4	Cities Service	19.17	18.25	18.66	18.96	18.97	19.12	19.13	19.18	21.68	19.34	19.21	19.23
5	Forest Oil	19.62	19.84	20.23	20.60	21.02	21.12	21.11	21.10	21.10	21.09	20.24	20.45
6	General American	17.45	17.86	19.69	19.60	19.96	20.65	20.84	21.25	21.08	20.72	20.68	20.53
7	Getty Oil	21.27	21.36	15.47	14.36	18.45	19.49	19.57	19.61	19.58	19.54	19.54	19.06
8	Gulf Oil	21.31	21.80	20.69	19.47	19.23	19.48	19.08	19.38	19.41	19.37	19.47	19.47
9	Humble Oil	20.62	21.02	20.72	20.24	20.07	18.73	20.01	20.07	20.39	20.47	20.50	20.28
10	Hunt Interests	21.93	22.12	20.99	19.01	20.16	20.29	21.33	21.01	21.12	22.76	21.25	21.19
11	Kerr-McGee	21.57	21.48	21.61	21.35	20.99	20.47	21.20	20.57	20.20	20.05	20.08	20.44
12	Marathon Oil	20.18	20.42	19.94	18.61	18.78	18.90	19.53	20.46	20.51	20.43	20.23	19.81
13	Mobil Oil	20.11	19.44	18.91	17.89	17.96	18.27	18.66	18.98	19.18	19.42	19.62	19.03
14	Pan American Petroleum	20.37	20.72	20.38	20.06	19.58	19.54	18.96	19.33	19.44	19.56	19.54	19.70
15	Pennzoil	20.08	19.61	17.35	17.86	17.37	17.51	17.59	17.79	17.78	19.13	19.47	18.45
16	Phillips Petroleum	22.09	22.01	21.54	21.59	21.83	21.66	21.32	21.18	21.12	20.79	20.79	21.44
17	Placid Oil	21.48	22.11	22.57	23.08	22.96	22.74	22.41	22.22	22.64	22.08	21.94	22.36
18	Shell Oil	22.10	19.26	17.43	18.95	19.12	20.08	21.02	21.33	20.80	20.41	20.41	20.16
19	Sun Oil	23.10	20.63	19.34	20.35	20.81	20.66	20.31	20.14	20.51	20.79	20.73	20.66
20	Superior Oil	20.60	21.82	21.88	21.48	20.70	20.68	21.58	22.43	22.38	22.31	22.35	21.72
21	Texaco	20.62	19.41	19.63	19.98	20.62	19.19	19.41	19.16	20.55	20.19	20.19	19.97
22	Union Oil	18.09	19.23	19.63	19.74	19.68	19.39	19.38	19.29	19.53	19.63	19.63	19.46
23	Union Texas Petroleum	18.22	18.24	19.21	19.39	19.39	18.21	18.39	18.22	18.27	19.26	19.38	18.62
24	Total	20.22	20.17	19.62	19.62	19.59	19.53	19.84	19.85	20.22	20.16	20.18	19.96

Source: B. G. Clay work paper, denoted as Schedule 91-2, Sheet 4 of 4, underlying Exhibit No. 91.

Exhibit No. 107

[10,836]

Schedule 6

SOUTHERN LOUISIANA AREA RATE PROCEEDING
Refunds of Certain Large Producing Companies Under Settlement Proposal
For 1960, 1961-1970
(Thousands of Dollars)

Line No.	Producers (Column 1)	Pre-1960 (2)	1960 (3)	1961 (4)	1962 (5)	1963 (6)	1964 (7)	1965 (8)	1966 (9)	1967 (10)	1968 (11)	1969 (12)	1970 (13)	Total (14)
1	Amerada Hess													195
2	Atlantic Richfield	383	86	1,212	1,438	1,441	1,428	910	987	1,042	1,165	1,474	1,474	15,999
3	California Company													733
4	Cities Service		5	142	224	311	87	292	98	66	228	334	341	2,360
5	Forest Oil		28			22	22				228		227	1,148
6	General American													1,863
7	Getty Oil												2,340	6,035
8	Gulf Oil													2,154
9	Kerr-McGee	210	343	275	421	228	333	221	215	214	214	214	214	1,575
10	Marathon Oil													2,441
11	Mobil Oil		95	105	94	100	94	61	57	54	54	54	54	1,011
12	Pan American Petroleum													5,238
13	Pennzoil		442	295	450	451	445	338	433	433	433	433	433	12,259
14	Phillips Petroleum	236	177	350	450	541	541	1,006	2,333	2,333	2,333	2,334	2,334	21,044
15	Placid Oil													2,177
16	Shell Oil													4,185
17	Sun Oil	34	727	1,143	1,447	1,442	1,441	1,436	1,822	2,814	2,814	2,814	2,814	97,279
18	Superior Oil													
19	Texaco	34	69	313	344	344	348	370	373	396	331	97	97	
20	Union Oil	14												
21	Union Texas Petroleum													
22	Total	1,073	2,834	3,992	5,431	5,604	5,944	5,539	7,538	8,489	11,633	10,383	10,383	

Source: B. G. Clay work paper, denoted as Schedule 91-4, Sheet 1 of 4, underlying Exhibit No. 91.

SOUTHERN LOUISIANA AREA RATE PROCEEDINGS
Interest on Refunds of Certain Large Producing Companies Under UDC Settlement Proposal
Pre 1960, 1960 - 1970
(Thousands of Dollars)

Line No.	Producers (Column A)	Pre 1960 (2)	1960 (3)	1961 (4)	1962 (5)	1963 (6)	1964 (7)	1965 (8)	1966 (9)	1967 (10)	1968 (11)	1969 (12)	1970 (13)	Total (14)
1	Amerada Hess	-	-	-	-	1	-	2	3	3	2	7	2	20
2	Atlantic Richfield	-	-	6	-	-	-	-	-	1	24	89	31	151
3	California Company	306	659	806	867	767	648	354	312	255	202	158	52	5,386
4	Cities Service	-	-	-	-	-	-	-	-	-	10	35	12	57
5	Forest Oil	3	4	2	1	9	26	2	-	-	2	6	1	56
6	General American	-	29	97	169	155	153	150	129	116	87	57	19	1,161
7	Getty Oil	-	-	-	-	-	-	-	-	-	13	33	18	64
8	Gulf Oil	-	-	-	-	-	-	-	-	-	25	64	29	138
9	Humble Oil	-	-	-	-	-	-	-	-	-	109	306	103	518
10	Shant Interests	6	39	60	52	53	52	39	100	93	70	44	34	617
11	Kerr-McGee	167	253	163	250	229	178	121	104	82	62	45	16	1,669
12	Marathon Oil	-	-	-	-	-	-	5	72	16	16	15	4	80
13	Mobil Oil	-	-	-	-	-	-	-	-	-	24	71	25	120
14	Pan American Petroleum	79	76	70	38	32	44	23	18	11	33	87	39	549
15	Pennzoil	-	-	-	-	-	-	-	-	-	3	13	5	21
16	Phillips Petroleum	261	334	362	368	338	310	165	155	110	74	57	19	2,143
17	Placid Oil	-	130	300	269	195	264	151	153	134	134	53	18	1,802
18	Shell Oil	-	-	-	-	-	-	657	679	566	426	233	77	2,369
19	Sun Oil	-	-	-	-	-	-	-	-	-	27	94	32	153
20	Superior Oil	27	334	763	1,111	967	905	569	576	689	481	276	91	6,989
21	Texaco	-	-	-	2	2	3	1	-	-	35	151	51	245
22	Union Oil	11	51	208	205	202	212	142	117	95	93	84	28	1,449
23	Union Texas Petroleum	-	-	-	-	-	-	-	-	-	1	4	2	7
24	Total	859	2,099	3,457	3,532	3,960	3,705	2,531	2,371	2,170	1,956	3,022	678	25,860

Source: B. G. Clay work paper, denoted as Schedule 91-4, Sheet 2 of 4, underlying Exhibit No. 91.

SOUTHERN LOUISIANA AREA RATE PROCEEDING
Net Revenues of Certain Large Producing Companies Under Settlement Proposal
1960-1970
(Thousands of Dollars)

Line No.	Producers Column 1	1960 (2)	1961 (3)	1962 (4)	1963 (5)	1964 (6)	1965 (7)	1966 (8)	1967 (9)	1968 (10)	1969 (11)	1970 (12)	Total (13)
1	Amerada Hess	1,212	1,264	1,775	1,935	2,052	2,168	2,232	2,486	2,646	3,058	3,279	24,327
2	Atlantic Richfield	19,600	21,426	23,858	26,962	27,131	36,267	34,588	35,360	40,222	40,538	45,673	349,725
3	California Company	14,570	16,837	20,060	19,728	20,740	20,409	29,508	31,359	33,983	36,134	42,704	285,034
4	Cities Service	8,060	6,874	5,977	8,421	9,178	9,718	10,290	10,875	14,475	16,263	19,883	119,991
5	Forest Oil	1,491	2,594	4,443	4,583	4,319	3,921	3,643	2,680	2,136	1,392	3,907	35,129
6	General American	650	4,228	5,998	5,822	7,274	8,668	10,279	14,350	17,508	21,518	20,282	115,877
7	Getty Oil	11,385	11,033	9,377	11,617	15,619	18,530	24,171	26,819	28,287	30,826	35,168	222,826
8	Gulf Oil	9,616	13,249	17,487	22,884	27,177	46,324	53,528	69,100	85,853	84,198	90,455	513,663
9	Humble Oil	13,134	15,782	22,583	29,909	36,949	53,150	66,839	78,921	88,707	110,721	122,086	638,771
10	Hunt Interests	5,886	5,536	5,137	4,977	5,624	5,298	9,046	9,630	9,090	8,774	9,124	78,172
11	Kerr-McGee	7,436	6,344	7,256	7,855	9,052	9,756	13,447	11,953	12,772	14,207	14,073	116,153
12	Marathon Oil	2,084	1,900	2,918	2,779	3,914	3,475	3,573	4,134	4,089	4,252	4,052	37,170
13	Mobil Oil	9,364	9,003	10,225	13,176	15,335	14,955	18,674	25,692	30,883	36,672	41,363	225,374
14	Pan American Petroleum	26,376	30,364	33,316	38,529	39,478	36,010	37,034	41,079	45,421	52,300	52,302	432,469
15	Pennzoil	2,771	3,549	3,454	5,896	4,797	4,363	5,263	5,946	6,965	10,300	14,343	66,544
16	Phillips Petroleum	9,899	8,472	8,674	9,529	9,581	9,434	11,079	11,353	11,804	14,175	14,175	118,195
17	Placid Oil	3,212	3,643	4,522	4,717	5,106	5,451	7,317	8,437	9,530	10,830	10,350	73,325
18	Shell Oil	35,656	32,131	32,334	38,606	40,800	40,155	43,571	48,890	58,853	70,256	73,831	515,184
19	Sun Oil	8,540	8,697	9,417	10,872	14,637	15,266	16,315	16,988	22,361	28,759	28,759	180,509
20	Superior Oil	24,188	24,061	24,347	33,878	35,218	35,338	38,396	40,397	41,995	44,465	43,550	390,053
21	Texaco	13,920	14,379	16,020	17,290	20,883	22,308	29,095	38,066	36,861	38,775	38,775	346,370
22	Union Oil	31,593	37,084	41,942	48,056	51,796	52,733	55,057	58,195	63,422	78,265	78,265	596,210
23	Union Texas Petroleum	16,279	17,105	13,199	16,221	16,344	16,825	16,065	16,662	16,602	16,787	15,002	177,116
24	Total	277,532	297,771	333,689	382,248	423,007	462,438	539,160	609,820	705,769	793,440	843,395	5,666,269

Source: B. G. Clay work paper, denoted as Schedule 91-4, Sheet 3 of 4, underlying Exhibit No. 91.

SOUTHERN LOUISIANA AREA RATE PROCEEDINGS
Unit Revenues of Certain Large Producing Companies Under Settlement Proposal
1960-1970
(Cents Per Mcf)

Line No.	Producers (Column 1)	1960 (2)	1961 (3)	1962 (4)	1963 (5)	1964 (6)	1965 (7)	1966 (8)	1967 (9)	1968 (10)	1969 (11)	1970 (12)	Total (13)
1	Amerada Hess	19.65	18.55	19.94	18.61	18.99	19.70	20.07	20.51	20.55	20.25	19.95	19.81
2	Atlantic Richfield	19.22	18.81	17.96	18.52	17.38	18.34	18.46	18.56	19.61	19.13	19.33	18.66
3	California Company	20.93	20.93	20.66	20.73	20.32	20.56	20.52	20.44	20.51	20.26	20.56	20.54
4	Cities Service	19.17	16.23	16.86	18.96	18.97	19.12	19.11	19.18	21.55	18.95	18.89	19.11
5	Forest Oil	19.55	19.82	20.22	20.53	20.63	21.10	21.10	21.10	20.91	20.30	19.97	20.51
6	General American	16.46	17.27	19.68	18.65	19.05	19.76	20.04	20.55	20.44	20.22	20.15	19.83
7	Getty Oil	21.27	21.36	15.47	14.34	18.43	19.49	19.57	19.61	19.50	19.22	19.25	19.96
8	Gulf Oil	21.31	21.80	20.49	19.47	19.25	19.40	19.02	19.28	19.36	19.18	19.29	19.40
9	Humble Oil	20.62	21.02	20.72	20.24	20.07	18.73	20.01	20.07	20.22	19.94	20.02	20.00
10	Hunt Interests	21.73	21.77	20.57	18.64	19.74	19.92	20.62	20.22	20.20	21.75	20.33	20.31
11	Kerr-McGee	20.62	20.59	20.24	20.27	20.11	19.82	20.68	19.81	19.85	19.44	19.54	19.98
12	Marathon Oil	20.18	20.42	19.94	18.61	18.78	18.93	19.18	20.10	20.03	19.76	19.54	19.53
13	Mobil Oil	20.11	19.44	18.91	17.89	17.94	18.27	18.66	18.92	19.07	19.05	19.30	18.56
14	Pan American Petroleum	20.29	20.65	20.34	20.01	19.53	19.51	18.94	19.30	19.36	19.25	19.25	19.59
15	Pennzoil	20.08	19.61	17.35	17.96	17.37	17.51	17.39	17.79	17.72	18.98	19.29	18.37
16	Phillips Petroleum	21.15	21.03	20.66	20.97	20.92	20.72	20.61	20.37	20.37	20.02	20.02	20.55
17	Placid Oil	20.35	20.43	20.52	20.63	20.62	21.21	21.05	20.98	20.97	21.02	20.90	20.85
18	Shell Oil	22.10	19.26	17.43	18.95	19.12	19.53	20.06	20.36	19.98	19.79	19.82	19.69
19	Sun Oil	23.10	20.63	19.36	20.35	20.81	20.66	20.31	20.16	20.74	20.11	20.11	20.43
20	Superior Oil	20.00	20.90	20.76	20.37	19.60	19.86	20.61	20.59	21.03	21.07	21.06	20.60
21	Texaco	20.62	19.41	19.63	19.97	20.61	19.19	19.41	19.16	20.46	19.70	19.70	19.79
22	Union Oil	18.05	19.07	19.28	19.58	19.31	19.26	19.15	19.12	19.36	19.43	19.43	19.24
23	Union Texas Petroleum	18.25	18.24	18.21	18.20	18.20	18.21	18.20	18.22	18.26	18.20	18.32	18.41
24	Total	20.11	19.90	19.50	19.34	19.32	19.32	19.56	19.65	19.89	19.68	19.72	19.63

Source: B. G. Clay work paper, denoted as Schedule 91-4, Sheet 4 of 4, underlying Exhibit No. 91.

SOUTHERN LOUISIANA AREA RATE PROCEEDINGS
Refunds to Pipelines Through 1970 Under:
(a) Opinion 546 Rates and (b) Proposed Settlement Rates
(000's omitted)

Line No.	Producers Column 1	Opinion 546 Total (2)	Opinion 546 Principal (3)	Opinion 546 Interest (4)	Settlement Total (5)	Settlement Principal (6)	Settlement Interest (7)
1	Consolidated Gas Supply	$ 1,006	$ 921	$ 85	$ 380	$ 344	$ 36
2	Florida Gas	2,858	2,434	424	1,250	1,041	208
3	Gas Gathering	210	176	34	24	23	1
4	Michigan Wisconsin	16,460	14,797	1,663	4,858	4,337	521
5	Natural Gas Pipeline	9,513	8,450	1,063	1,734	1,611	124
6	Park Pipe Line	241	223	18	75	69	6
7	Southern Natural	47,928	36,751	11,177	20,478	17,792	6,685
8	Tennessee 1/	117,531	93,852	23,679	52,575	40,343	12,233
9	Texas Eastern	4,144	3,761	383	981	909	72
10	Texas Gas	9,597	8,385	1,212	2,973	2,586	387
11	Transco	29,326	25,081	4,245	10,655	8,745	1,910
12	Trunkline	31,534	25,429	6,105	13,618	10,430	3,188
13	United Fuel	34,214	29,230	4,984	9,217	7,862	1,355
14	United Gas Pipe Line	71,866	60,723	11,143	26,402	21,810	4,592
15	Total	$376,428	$310,213	$66,215	$149,220	$117,902	$31,318

1/ Includes Jupiter.

Source: B. G. Clay work paper, denoted as Schedule 91-5, Sheet 1 of 2, underlying Exhibit No. 90, Schedule 1.

SOUTHERN LOUISIANA AREA RATE PROCEEDINGS
Refunds of Producers through 1970 Under:
(a) Opinion 546 Rates and (b) Proposed Settlement Rates
(000's omitted)

Line No.	Company	Opinion 546 Total	Opinion 546 Principal	Opinion 546 Interest	Settlement Total	Settlement Principal	Settlement Interest
	Column 1	(2)	(3)	(4)	(5)	(6)	(7)
1	Amerada	$ 944	$ 821	$ 123	$ 215	$ 195	$ 20
2	Atlantic Richfield	8,540	7,730	810	2,121	1,970	151
3	California Company	42,280	31,787	10,493	19,285	13,899	5,386
4	Cities Service Gas	3,352	3,010	342	809	752	57
5	Forest	4,899	3,520	1,379	311	243	68
6	General American	13,353	10,694	2,659	5,128	3,967	1,161
7	Getty	4,417	4,206	211	1,232	1,148	84
8	Gulf	7,501	6,868	633	2,003	1,865	138
9	Humble	24,455	22,589	1,866	7,153	6,635	518
10	Hunt Interests	7,342	6,110	1,232	3,091	2,474	617
11	Kerr-McGee	10,591	8,028	2,563	5,978	4,295	1,683
12	Marathon	2,025	1,767	258	616	536	80
13	Mobil	6,446	5,898	548	1,691	1,572	120
14	Pan American	8,483	7,421	1,062	3,201	2,641	560
15	Pennzoil	1,051	974	77	302	281	21
16	Phillips	12,160	9,268	2,892	7,555	5,412	2,143
17	Placid	14,251	11,020	3,231	7,091	5,289	1,802
18	Shell	36,568	31,252	5,316	14,717	12,329	2,388
19	Sun & Sunray DX	7,405	6,845	560	2,158	2,005	153
20	Superior	59,602	46,906	12,696	28,633	21,644	6,989
21	Texaco	17,245	15,357	1,888	3,422	3,177	245
22	Union Oil of California	17,047	13,506	3,541	6,296	4,849	1,446
23	Union Texas	381	353	28	112	105	7
24	Total Sample (82.5%)	$310,558	$255,930	$54,628	$123,119	$ 97,279	$25,840
25	Grand Total 1/	$376,428	$310,213	$66,215	$149,220	$117,902	$31,318

All Sales	Onshore	Offshore
Cont. Date Pre 10/1/61*	16.5¢	17.0¢
Cont. Date 1/1/61 - 10/1/68	19.5	18.0
Cont. Date Post 10/1/68	20.0	18.5

*All oil well gas priced at rates shown for this vintage

	Onshore	Offshore
*Sales Prior to 1/1/65	20.625¢	19.625¢
Sales 1/1/65 - 10/1/68	21.25	20.25
Sales 10/1/68 - 1/1/71	2/	2/

*Refunds at 30.5% of Opinion 546 Refunds

1/ Factored up on the basis that sales for the sample companies amounted to 82.5% of total sales in 1968.

Source: B. G. Clay work paper, denoted as Schedule 91-5, Sheet 2 of 2, underlying Exhibit No. 90, Schedule 2.

Exhibit No. 108

[10,844]

DOCKET NO. AR69-1
AREA RATE PROCEEDING
(SOUTHERN LOUISIANA AREA)

Table A
Sheet 1 of 3

CAPITAL GENERATED INTERNALLY BY THE 14 LARGEST SELLERS OF INTERSTATE GAS IN SOUTHERN LOUISIANA
YEAR 1969

Line No.		Amount (000 Dollars)	Total
1	Gulf Oil Co.		
2	Funds from Depreciation, Depletion and Amortization	450,770	
3	Funds from Retained Earnings [a]	298,995	
4	Total Capital Generated		749,765
5	Humble Oil & Refining Co. (Standard Oil Co. of N.J.)[b]		
6	Funds from Depreciation, Depletion and Amortization	856,840	
7	Funds from Retained Earnings [a]	241,189	
8	Total Capital Generated		1,098,029
9	Union Oil of California		
10	Funds from Depreciation, Depletion and Amortization	132,848	
11	Funds from Retained Earnings [a]	85,221	
12	Total Capital Generated		218,069
13	Shell Oil Co.		
14	Funds from Depreciation, Depletion and Amortization	351,831	
15	Funds from Retained Earnings [a]	129,373	
16	Total Capital Generated		481,204
17	Texaco Inc.		
18	Funds from Depreciation, Depletion and Amortization	345,264	
19	Funds from Retained Earnings [a]	347,459	
20	Total Capital Generated		692,723
21	Pan American Petroleum Co. (Standard Oil Co. of Indiana)[b]		
22	Funds from Depreciation, Depletion and Amortization	292,405	
23	Funds from Retained Earnings [a]	157,779	
24	Total Capital Generated		450,184

Exhibit No. 108

[10,845]

Table A
Sheet 2 of 3

DOCKET NO. AR69-1
AREA RATE PROCEEDING
(SOUTHERN LOUISIANA AREA)

CAPITAL GENERATED INTERNALLY BY THE 14 LARGEST SELLERS OF INTERSTATE GAS IN SOUTHERN LOUISIANA
YEAR 1969

Line No.		Amount (000 Dollars)	Total
1	Superior Oil Co.		
2	Funds from Depreciation, Depletion and Amortization	16,524	
3	Funds from Retained Earnings a/	9,880	
4	Total Capital Generated		26,404
5	Mobil Oil Corp.		
6	Funds from Depreciation, Depletion and Amortization	355,764	
7	Funds from Retained Earnings a/	206,318	
8	Total Capital Generated		562,082
9	The California Co. (Standard Oil Co. of Calif.) b/		
10	Funds from Depreciation, Depletion and Amortization	312,909	
11	Funds from Retained Earnings a/	219,219	
12	Total Capital Generated		532,128
13	Getty Oil Co.		
14	Funds from Depreciation, Depletion and Amortization	108,786	
15	Funds from Retained Earnings a/	109,426	
16	Total Capital Generated		218,212
17	Atlantic Richfield Co.		
18	Funds from Depreciation, Depletion and Amortization	227,193	
19	Funds from Retained Earnings a/	106,339	
20	Total Capital Generated		333,532
21	General American Oil Co. of Texas a/		
22	Funds from Depreciation, Depletion and Amortization	14,201	
23	Funds from Retained Earnings a/	15,730	
24	Total Capital Generated		29,931

Exhibit No. 108

[10,846]

Table A
Sheet 3 of 3

DOCKET NO. AR69-1
AREA RATE PROCEEDING
(SOUTHERN LOUISIANA AREA)

CAPITAL GENERATED INTERNALLY BY THE 14 LARGEST SELLERS OF INTERSTATE GAS IN SOUTHERN LOUISIANA
YEAR 1969

Line No.		Amount (000 Dollars)	Total
1	Continental Oil Co.		
2	Funds from Depreciation, Depletion and Amortization	120,031	
3	Funds from Retained Earnings a/	77,126	
4	Total Capital Generated		197,157
5	Sun Oil Co.		
6	Funds from Depreciation, Depletion and Amortization	120,221	
7	Funds from Retained Earnings a/	83,732	
8	Total Capital Generated		203,953
9	Total, 14 companies		2,793,373

a/ After dividends.

b/ Reflects parent company data.

c/ Year ending June 30.

Sources: Moody's 1970 Industrial Manual
Table K, Exh. 109

Exhibit No. 108

[10,847]

Table B
Sheet 1 of 3

DOCKET NO. AR69-1
AREA RATE PROCEEDING
(SOUTHERN LOUISIANA AREA)

CAPITAL OBTAINED EXTERNALLY BY THE 14 LARGEST SELLERS OF INTERSTATE GAS IN SOUTHERN LOUISIANA AVERAGE FOR 1960-1969, INCLUSIVE

Line No.		Year	Amount (Dollars)	Total
1	Gulf Oil Co.			
2	Debentures	1969	60,000,000	
3	"	1968	240,000,000	
4	"	1966	100,000,000	
5	Total Capital Obtained			400,000,000
6	Humble Oil & Refining Co. (Standard Oil Co. of N.J.) a/			
7	Debentures	1968	250,000,000	
8	"	1967	250,000,000	
9	Total Capital Obtained			500,000,000
10	Union Oil of California			
11	Debentures	1968	150,000,000	
12	"	1961	120,000,000	
13	Total Capital Obtained			270,000,000
14	Shell Oil Co.			
15	Debentures	1969	60,000,000	
16	"	1967	150,000,000	
17	"	1961	200,000,000	
18	Total Capital Obtained			410,000,000
19	Texaco, Inc.			
20	Debentures	1968	75,000,000	
21	"	1967	200,000,000	
22	Total Capital Obtained			275,000,000

Exhibit No. 108

[10,848]

Table B
Sheet 2 of 3

DOCKET NO. AR69-1
AREA RATE PROCEEDING
(SOUTHERN LOUISIANA AREA)

CAPITAL OBTAINED EXTERNALLY BY THE 14 LARGEST SELLERS OF INTERSTATE GAS IN SOUTHERN LOUISIANA AVERAGE FOR 1960-1969, INCLUSIVE

Line No.		Year	Amount (Dollars)	Total
1	Pan American Petroleum Co. (Standard Oil Co. of Indiana) a/			
2	Debentures	1969	50,000,000	
3	"	1968	225,000,000	
4	"	1966	175,000,000	
5	Bonds	1965	25,000,000	
6	Total Capital Obtained			475,000,000
7	Superior Oil Co.		-0-	-0-
8	Mobil Oil Co.			
9	Debentures	1963	200,000,000	
10	Bonds	1969	35,000,000	
11	Total Capital Obtained			235,000,000
12	The California Co. (Standard Oil Co. of Calif.) a/			
13	Debentures	1968	75,000,000	
14	"	1967	200,000,000	
15	Secured Notes	1967	25,000,000	
16	Total Capital Obtained			300,000,000
17	Getty Oil Co.		-0-	-0-
18	Atlantic Richfield Co.			
19	Debentures	1969	150,000,000	
20	"	1967	100,000,000	
21	"	1963	150,000,000	
22	Common Stock	1969	168,000,000	
23	Total Capital Obtained			568,000,000

Exhibit No. 108

[10,849]

Table B
Sheet 3 of 3

DOCKET NO. AR69-1
AREA RATE PROCEEDING
(SOUTHERN LOUISIANA AREA)

CAPITAL OBTAINED EXTERNALLY BY THE 14 LARGEST SELLERS OF INTERSTATE GAS IN SOUTHERN LOUISIANA AVERAGE FOR 1960-1969, INCLUSIVE

Line No.		Year	Amount (Dollars)	Total
1	General American Oil Co. of Texas		-0-	-0-
2	Continental Oil Co.			
3	Debentures	1969	100,000,000	
4	"	1968	20,000,000	
5	"	1961	100,000,000	
6	Common Stock	1967	146,501,228	
7	Total Capital Obtained			366,501,228
8	Sun Oil Co.			
9	Debentures	1965	100,000,000	
10	"	1962	75,000,000	
11	Total Capital Obtained			175,000,000
12	Total, 14 companies			3,974,501,228
13	Average Per Year			397,450,122

a/ Reflects parent company data.

Sources: Standard & Poor's Corporation Records
Table E, Exh. 100

Exhibit No. 108

[10,850]

Table C
Sheet 1 of 3

DOCKET NO. AR69-1
AREA RATE PROCEEDING
(SOUTH LOUISIANA AREA)

CASH AND MARKETABLE SECURITIES OF THE 14 LARGEST SELLERS OF INTERSTATE GAS IN SOUTHERN LOUISIANA, AS OF DECEMBER 31, 1969

Line No.		Amount (000 Dollars)	Total
1	Gulf Oil Co.		
2	Cash	87,701	
3	Marketable Securities	465,113	
4	Total		552,814
5	Humble Oil & Refining Co. (Standard Oil Co. of N.J.)[1/]		
6	Cash	408,123	
7	Marketable Securities	868,107	
8	Total		1,276,230
9	Union Oil of California		
10	Cash	25,770	
11	Marketable Securities	30,388	
12	Total		56,158
13	Shell Oil Co.		
14	Cash	45,446	
15	Marketable Securities	242,965	
16	Total		288,411
17	Texaco Inc.		
18	Cash	151,689	
19	Marketable Securities	249,315	
20	Total		401,004
21	Pan American Petroleum Co. (Standard Oil Co. of Indiana)[2/]		
22	Cash	105,175	
23	Marketable Securities	166,897	
24	Total		272,072

Exhibit No. 108

[10,851]

Table C
Sheet 2 of 3

DOCKET NO. AR69-1
AREA RATE PROCEEDING
(SOUTH LOUISIANA AREA)

CASH AND MARKETABLE SECURITIES OF THE 14 LARGEST SELLERS OF INTERSTATE GAS IN SOUTHERN LOUISIANA AS OF DECEMBER 31, 1969

Line No.		Amount (000 Dollars)	Total
1	Superior Oil Co.		
2	Cash		
3	Marketable Securities	43,753	
4	Total	160,066	
			203,819
5	Mobil Oil Co.		
6	Cash		
7	Marketable Securities	144,574	
8	Total	583,333	
			727,907
9	The California Co. (Standard Oil Co. of Calif.) a/		
10	Cash		
11	Marketable Securities	122,049	
12	Total	108,981	
			231,030
13	Getty Oil Co.		
14	Cash		
15	Marketable Securities	25,100	
16	Total	81,232	
			106,332
17	Atlantic Richfield Co.		
18	Cash		
19	Marketable Securities	203,849	
20	Total	11,388	
			215,237
21	General American Oil Co. of Texas b/		
22	Cash		
23	Marketable Securities	5,874	
24	Total	5,250	
			11,124

Exhibit No. 108

[10,852]

Table C
Sheet 3 of 3

DOCKET NO. AR69-1
AREA RATE PROCEEDING
(SOUTH LOUISIANA AREA)

CASH AND MARKETABLE SECURITIES OF THE 14 LARGEST SELLERS OF INTERSTATE GAS IN SOUTHERN LOUISIANA AS OF DECEMBER 31, 1969

Line No.		Amount (000 Dollars)	Total
1	Continental Oil Co.		
2	Cash	199,768	
3	Marketable Securities	108,104	
4	Total		867,872
5	Sun Oil Co.		
6	Cash	66,002	
7	Marketable Securities	35,448	
8	Total		101,450
9	Total, 14 Companies		4,711,460

a/ Reflects parent company data.

b/ Year ending June 30.

Sources: Moody's 1970 Industrial Manual
Table E, Exh. 100

Exhibit No. 108

[10,853]

Table D
Sheet 1 of 3

DOCKET NO. AR69 - 1
AREA RATE PROCEEDING
(SOUTH LOUISIANA AREA)

WORKING CAPITAL RATIO OF 14 LARGEST SELLERS
OF INTERSTATE GAS IN SOUTHERN LOUISIANA

Line No.		Amount (000 Dollars)	Net Working Capital (000 Dollars)
1	Gulf Oil Co.		
2	Current Assets	2,325,294	
3	Current Liabilities	1,236,597	
4	Net Working Capital		1,088,697
5	Working Capital Ratio	1.88:1.0	
6	Humble Oil & Refining Co. (Standard Oil Co. of N. J.) a/		
7	Current Assets	5,634,028	
8	Current Liabilities	3,789,273	
9	Net Working Capital		1,844,755
10	Working Capital Ratio	1.49:1.0	
11	Union Oil of California		
12	Current Assets	568,028	
13	Current Liabilities	390,613	
14	Net Working Capital		177,415
15	Working Capital Ratio	1.45:1.0	
16	Shell Oil Co.		
17	Current Assets	1,255,089	
18	Current Liabilities	724,642	
19	Net Working Capital		530,447
20	Working Capital Ratio	1.73:1.0	
21	Texaco Inc.		
22	Current Assets	2,441,038	
23	Current Liabilities	1,296,400	
24	Net Working Capital		1,144,638
25	Working Capital Ratio	1.88:1.0	

[11,030]

UNITED STATES OF AMERICA
FEDERAL POWER COMMISSION

Before Commissioners: Lee C. White, Chairman; L. J. O'Connor, Jr., Carl E. Bagge, John A. Carver, Jr., and Albert B. Brooke, Jr.

Docket No. AR69-1

AREA RATE PROCEEDING
OFFSHORE SOUTHERN LOUISIANA FEDERAL DOMAIN
AND DISPUTED AREAS

ORDER INSTITUTING INVESTIGATION AND PROPOSED RULEMAKING

(Issued March 20, 1969)

By Opinion Nos. 546 and 546-A and accompanying orders we established just and reasonable rates for sales of natural gas in Southern Louisiana, including the offshore areas. In Opinion No. 546 we noted that the record in that proceeding did not contain separate cost figures for the results of drilling in the Federal domain or for offshore generally. (Mimeo p. 135). We expressly invited a petition to reconsider the far offshore rates (p. 138).

On January 8, 1969, the New York Public Service Commission filed a request that the Commission institute an investigation into the adequacy of gas reserves held or controlled by the major producers and pipelines,

and the claims of a shortage of natural gas. In explaining its reasons why it believes an investigation is necessary, the New York Commission referred to a December 16, 1968, letter sent by the American Gas Association to the Commission which it interprets as asserting that distributors and pipelines are being refused service by many producers on the ground that the prices found in our area decisions to

[11,031]

be just and reasonable are inadequate. The New York Commission gave three reasons why such a refusal to serve, if it exists, is sufficiently serious to warrant formal investigation:

> First, such a shortage, if proven on an evidentiary record, would require a review to determine the reasons therefor and the appropriate regulatory response thereto.
>
> Second, to the extent that the actual or threatened withholding of gas was being used to coerce parties to FPC proceedings to modify their positions, it would be essential for the FPC to take corrective measures to protect the integrity of its processes.
>
> Third, any group effort to fix the price at which natural gas shall be sold in interstate commerce, and any group refusal to sell gas to particular customers or groups of customers, would constitute 'apparent violations of the Federal antitrust laws' which the Commission is obliged to call to the attention of the Attorney General under Section 20(a) of the Natural Gas Act.

The New York Commission suggested that the scope of the investigation might appropriately be limited to the

offshore area of Southern Louisiana, noting that because of the importance of this area the need for reliable information with respect thereto is especially compelling. The Secretary of the Federal Power Commission issued public notice of the investigation request on January 16, 1969, Docket No. RI69-470, inviting any interested persons to submit written comments thereon.

On January 22, 1969, certain producer-respondents in the Southern Louisiana area proceeding filed a joint

[11,032]

motion [1] seeking a limited reopening of the record in Docket No. AR61-2. Movants ask the reopening be granted in order "to receive additional evidence demonstrating the substantial changes in supply-demand relationships for natural gas which have occurred since the record was closed over three years ago." Movants state that if a limited reopening is granted they would promptly tender evidence covering the following matters:

1. The unavailability of adequate gas supplies to satisfy present and reasonable anticipated future consumer demands.
2. The need for *immediate* corrective action due to the lead time required before improved producer price incentives can achieve higher levels of finding and development of new reserves.

[1] The movants are listed in the motion as Texaco Inc., Gulf Oil Corporation and The British-American Oil Producing Company, Pan American Petroleum Corporation, Shell Oil Company, Union Oil Company of California and Humble Oil & Refining Company. Numerous other parties have subsequently filed similar motions or joined in the motion. Oppositions have also been filed.

3. The appropriate regulatory response to the present serious gas supply problem.
4. The significance and importance of revenues from flowing gas as a source of capital funds for the substantial new investments required to reverse the dangerous current trends in supply and demand.

As to the investigation requested by the New York Public Service Commission, movants ask that that investigation,

[11,033]

if the request is granted, be consolidated in the proposed reopening of Docket No. AR61-2.

Additionally, in responding to various requests for further oral argument in Docket No. AR61-2, certain distributor interveners suggested that the Commission obtain additional evidence as to the need of revision of the offshore price applicable to future contracts.

In Opinion Nos. 546 and 546-A we noted our concern with respect to the adequacy of the evidence in the record relating to cost of gas produced in the Federal domain [2] along with our desire to encourage a continued active program of exploration in the area.[3] This in part led us to establish a series of price differentials between state domain and Federal domain production which is less that the amount of the State tax. Most importantly, however, we extended a clear invitation in the Opinion for the filing of a petition to reconsider the far offshore rates whenever the parties believed that sufficient evi-

[2] Mimeo pp. 129, 130, 135.

[3] Mimeo p. 135.

dence was at hand, or could be presented, to indicate a need for a change in price.

We observed in Opinion No. 546 that "certain input costs are higher in deep offshore waters than elsewhere" but that "Gas reserves data have not been satisfactorily correlated, however, with such costs" (mimeo p. 130). We similarily acknowledged the unsatisfactory status of available data on time lags and called on staff and interested parties "to undertake a more exhaustive inquiry * * * both nationally and for key production areas and subareas, such as the offshore Federal domain of Southern Louisiana." (Mimeo p. 38). We believe that a further proceeding investigating the correlation between

* * * *

[11,037]

(C) A conference will be held at the Commission offices at 441 G Street, N.W., Washington, D.C., between respondents, interveners, and Commission staff concerning the issues and procedures to be followed. The Chief Examiner, or an Examiner designated by him, shall preside at the hearing hereby called and shall prescribe the date thereof. Upon completion of this conference and any other conferences which may be deemed necessary, a transcript thereof shall be transmitted to the Commission for further action.

(D) Any party who has intervened in Docket No. AR61-2 may become an intervener in this proceeding by filing notice thereof within 30 days of the date of issuance hereof in the manner provided by Section 1.8(a)(1) of the Commission's Rules of Practice and Procedure. Other persons may within such 30 days file petitions to

intervene or notices of intervention as provided by Section 1.8 of the Rules of Practice and Procedure.

(E) In order that the issues involved herein may be properly determined, offshore lessees are hereby directed pursuant to the provisions of Sections 8, 10, and 14 of the Natural Gas Act to grant to authorized members of the staff of the Federal Power Commission, during regular business hours, free access to their property and access to and the right to inspect and examine all of their accounts, records, and memoranda including, but not limited to, the books, papers, correspondence, contracts, agreements, maps, reports of engineers, logs, and other data pertinent to the investigation herein authorized and upon staff request shall furnish copies of such material to the staff.

(F) The Secretary shall cause a copy of this order to be published in the FEDERAL REGISTER and served upon each of the respondents set out in Appendix A and upon interested State Commissions as is provided for in Section 1.19 of the Commission's Rules of Practice and Procedure.

By the Commission. Commissioner Carver concurring filed a separate statement appended hereto.

[SEAL]

GORDON M. GRANT
Secretary

months for lease acquisition (TR. 5901). Mr. Sherwin's adjustment should be rejected. As Mr. Allen stated, the Auten study fails to reflect the effect of advance payments (TR. 6487).[3] In addition the Auten Exhibit covers the time period 1963-1968. In 1963 the supply situation was considerably more comfortable than the current picture. The current demand for gas would have a tendency to reduce time lag as wells would be brought into production as soon as possible. Similarly, in 1963 the network of offshore pipelines was considerably less than at the present, and this too would affect time lags associated with offshore gas wells and leases. A time lag of one year recommended by Mr. Loring appears reasonable at this time and should be adopted.

2. *Production life should be no more than nine years.*

The record before the Commission indicates that no more than an 18 year depletion period be used. As Mr. Loring testified, depletion life of gas wells has shortened within

[3] Advance payments were defined as the payment by the gas purchaser to the owned of the gas, payments made prior to delivery of the gas and then made up after delivery begins (TR. 6486). *To the extent* advance payments are allowed, which the producers may pay back over production, no return is appropriate; that is no allowance for lag would be appropriate at all and the return allowed for the production period would not apply in whole or in part because advance payments are consumer contributed capital. Compare *Alabama-Tennessee Natural Gas Co.* v. *FPC*, 359 F. 2d 318, 340 (CA5, 1966).

V. THE SETTLEMENT PROPOSED BY VARIOUS PARTIES IS UNJUST AND UNREASONABLE

On December 11, 1970 the New York State Public Service Commission filed its objections to the settlement proposal in these proceedings. We there objected to the price, bonus, refund waiver, and certain other settlement provisions. We reassert those objections and incorporate our filing as part of this brief. The settlement proposals for gas prices, escalations, and bonuses substantially exceed the ceilings, subject to moratoria, which we recommend. Those settlement proposals are wholly unreasonable and unjustified. Furthermore, the settlement proposals for refund waiver remain illegal and unjustified, as we have further explained in this brief. At this point, we should add to the objections reflected in our December 11, 1970 filing the following material, which demonstrates that producers should be charged at least 4¢ per Mcf per 100 miles for transportation of producer liquids by pipelines, not the 2¢ provided in the settlement proposal.

Witness Anderson testifying for the Pipeline Purchaser Group recommended that a transportation fee for liquefiable hydrocarbons and related fuels be established at 2¢ per Mcf for 100 miles. Mr. Anderson's stated purpose in presenting this testimony was to confirm the reasonableness of the transportation fee for liquefiable hydrocarbons as set forth in Section 5.2 of the settlement proposal (TR 6395-96). Although Section 5 of this

proposal is entitled "Transportation of Liquid and/or Liquefiable Hydrocarbons for Producers in Southern Lou-

isiana Area" Mr. Anderson supported the proposed 2¢ charge by accumulating the transmission costs for seven Southern Louisiana pipelines and spreading those transmission costs over the commodity miles of transmission for the same pipeline companies (TR 6396). On this basis an average unit cost per 100 miles of 2.081¢ was derived. Mr. Anderson's presentation, based on these pipeline costs for their entire system, greatly understates the real cost of transporting these liquefiable hydrocarbons in Southern Louisiana. Since most transportation in this area is from offshore to onshore, a better indicator of the actual cost of transporting these liquids for producers would be the cost of operating these offshore to onshore systems. Of the seven pipelines listed by Mr. Anderson in Exhibit 85, Southern Tennessee, Texas Eastern and Trunkline operate offshore systems (TR 6730). Those companies listed in Exhibit 85 which do not have offshore systems have gas transported for them by other pipelines (TR 6731). Information obtained from the public records of the Commission shows that the cost for the companies which transport to shore is substantially above the 2¢ Mcf figure developed by Mr. Anderson.

Sea Robin Pipeline Company, for example, transports gas under agreement for United Fuel Gas Company from offshore to onshore Louisiana. The demand charge for this service listed in

the Sea Robin tariff (Rate Schedule X-3) on file with the Commission is $1.21 per month. Dividing this charge by 30.42 a unit cost of 3.98¢ per Mcf is determined.

Tidal Transmission Company has on file with the Commission a transportation agreement between it and Natu-

ral Gas Pipeline Company whereby Tidal transports gas purchased by Natural offshore to onshore at a demand charge of 3.3¢ per Mcf.

Texas Eastern Transmission Corporation in Docket No. RP70-29 segregated the cost of service for its offshore facilities. This cost amounted to $6,696,000. Although Texas Eastern had been allowed a 4¢ per Mcf condition for its offshore facilities, the company exhibited a loss of over $4,100,000 on this service.

Texas Gas Transmission Corporation has gas transported for it by Michigan-Wisconsin Pipeline Company. Under the agreement entered into by these parties, Michigan-Wisconsin is allowed a demand charge of $1.37 per Mcf per month—well over 4¢ per Mcf (Docket No. RP69-41, Exhibit 9).

Similarly, Southern Natural has gas transported for it by Sea Robin at a demand charge of approximately 4¢ per Mcf.

These examples of the actual cost of operating offshore to onshore systems, in addition to the fact that construction of pipelines offshore are more expensive than onshore pipelines (TR 6725), demonstrate that Mr. Anderson has

[12,281]

understated costs. Instead of 2¢ per Mcf, the cost allowed for transporting these liquefiable hydrocarbons should more properly be 4¢ per Mcf or more.

Further adjustment must be made to Pipeline Witness Moye's calculation of 20¢ per barrel for transportation of liquid hydrocarbons in a two-phase pipeline system (TR 6404). Mr. Moye based his determination on Mr.

Anderson's recommended charge of 2¢. Adjusting this 2¢ charge to a more reasonable 4¢ cost would increase Mr. Moye's recommended rate to 40¢ per barrel.

CONCLUSION

For the reasons stated, the Commission should fix the ceiling rates which we recommend (Argument III), should impose an indefinite moratorium against future rate increases, should establish quality standards and related adjustments as provided in Opinion 546, should order payment of refunds owed (in installments with interest, where appropriate), and should reject the settlement proposed in this proceeding.

Respectfully submitted,

/s/ Alan J. Roth
ALAN J. ROTH
Executive Assistant to
the Chairman

/s/ Joseph J. Klovekorn
JOSEPH J. KLOVEKORN
Staff Counsel

April 15, 1971
Albany, New York

Service of Copies to all parties on
the Secretary's Service List for the
Proceeding in Docket No. AR69-1

[12,653]

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL POWER COMMISSION

Docket Nos. AR61-2, *et al.*
AR69-1

IN THE MATTERS OF
AREA RATE PROCEEDINGS
(SOUTHERN LOUISIANA AREA)

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[12,654]

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ing the area rates. Otherwise, the pipeline's cost of production would not be included in any rate-making procedures, and the Commission would be in the position of regulating an important segment of the producing industry with ceiling rates which were determined in proceedings which completely ignored the costs incurred by such segment.

b. The Exclusion of Cycling Lease Data

In estimating the historical gas-well gas cost in the Southern Louisiana area for the test year 1969 to be 24.03 cents using a 13 percent rate of return and 25.81 cents using a 16 percent rate of return, Mr. Auten excluded cycling lease costs and volumes from his computations. The Commission has long recognized that cycling leases are not typical gas producing leases (34 FPC at 297). This conclusion was reiterated by the Commission in Opinion 546 where it said:

> ". . . Cycling leases contain investment in additional equipment, such as reinjection wells and field compressors, with their attendant operating costs which are not incurred on non-cycling leases. Cycling is performed in order to enhance the recovery of liquids. . . ." (40 FPC at 596)

There are major differences in ownership and operating practices which set cycling leases apart. Most cycling properties result from the unitization of numerous leases. Such unitization is essential because if all leases overlying a given reservoir were not included in the unit which was reinjecting gas, the leases which were not in the unit would be able to produce the reinjected gas for sale. Unitization frequently encompasses an area overlying nu-

merous gas reservoirs, one or more of which are being cycled, and one or more of which are selling gas instead of cycling. Even so there are no separate cost records maintained for each reservoir, nor is it feasible to attempt separate costing. In addition, cycling plant costs and reinjection facilities costs are normally included in the cost records for the unitized cycling properties. Consequently, it is not

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feasible to attempt a separation of plant operations from lease operations.

Differences in operating practice on cycling leases from normal gas production operations have a major impact on cost allocation techniques. When allocation techniques which the Commission has applied in past proceedings are applied to cycling leases, the results give the illusion of significantly lower unit costs on these leases. That illusion is created by the effect of tremendously high gas production volumes on cycling leases. When reservoirs are cycled, the gas is brought to the surface, the liquids extracted, and the residue reinjected. The cycled volumes are handled at very high rates as compared to normal gas production. This is attributable to several factors with the principal ones being (1) no contractual volume limitations, (2) no state proration limitations, (3) no loss of reservoir pressure because of the reinjection operations and (4) economics of liquid extraction operations require high volumes of throughput. As a result, the production rates on a cycling reservoir are normally much higher than on other typical gas operations, yet little or none of those volumes are sold until the major portion of the liquids have been depleted. At that time cycling operations revert to normal gas production and

sales operations, and it is at that time that they should be included in the gas costing process (48:6177).

The Commission should not be misled by the argument that cycling leases must be included in the costing process because gas sales are made from those leases. As explained above, those sales are normally made from non-cycled reserovirs which happen to underlie the unitized cycling property. There are no separable costs available for those sales volumes, and viewed in that light they are closely akin to combination type leases.

The additional cost allocation problems presented by these leases are similar to those encountered on the oil-casinghead and combination leases. Because the apportionment of joint costs on casinghead and combination leases do not yield results which may be accepted as reliable guides, the cost estimates made by the Commission and

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by the Examiners in prior area rate proceedings have been limited to the gas-well gas lease categories. In *Permian*, the Commission did not reach the further issue of the treatment which would be appropriate for cycling lease costs and volumes. In Docket AR61-2 there was some cycling data available, but the Commission was not presented with the question of whether all cycling lease data, both volumes and costs, should be excluded.

Because cycling properties are reinjecting gas for the purpose of preventing retrograde condensation in the reservoirs, the operation of these properties during the cycling process is principally a liquid recovery operation (48:6177). The volumes and costs of cycling leases should be excluded from the composites used in the flowing gas

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cost estimates because they distort the gas-well gas cost estimates by unnecessary and unrealiable allocations and by adding unrealistically high volumes which are not sold when produced.

c. Excluding Hugoton-Panhandle Data From the Relative Cost Ratios

In applying the relative cost method to the allocation of joint production costs, Mr. Auten recommended that if Continental U. S. ratios were to be used in the allocation, several adjustments were required to the data used in the ratio. These were (1) the exclusion of Pricing Areas 14 and 19 (Texas District 10 and Kansas), (2) the exclusion of shut-in costs on a well basis rather than a lease basis, and (3) the use of net investment instead of gross investment in computing the ratios.

In excluding Pricing Areas 14 and 19 from the Continental U. S. relative cost ratios, Mr. Auten excluded both the costs and volumes of the two areas which are dominated by the Hugoton-Panhandle Field, pointing out that this field was generally quite shallow in relation to most other significant gas fields and was largely the result of investment made many years ago at cost levels which are not representative of those presently being incurred (48:6174). In his rebuttal testimony (52:6936-37), and in his Exhibit 95, Mr. Auten estimated the effect of excluding the remainder of the

[12,800]

Hugoton-Panhandle data by excluding Pricing Area 16 (Oklahoma-Panhandle) along with Pricing Areas 14 and 19. This approach was consistent with the testimony of Witness Gillespie (52:6991-7001).

The purpose of a relative cost ratio is to allocate costs between gas and liquids on gas-condensate-with-lease-separation leases. Such a ratio, in order to fulfill its purpose, should be as nearly representative as possible of the joint product lease cost being allocated. The testimony and exhibits of Witnesses Auten, Larson and Gillespie establish that Continental U. S. legs are dominated by the Hugoton-Panhandle Field. Pricing Areas 14, 16 and 19 must be excluded from the relative cost ratios if Continental U. S. legs are to be representative of Southern Louisiana production.

d. Shut-in Leases Should Not Be Excluded From the Ratios Unless Shut-in Well Data Are Also Excluded

In determining the range of reasonable flowing gas cost estimates, if the relative cost method is to be used to allocate joint production costs, and if shut-in costs are to be excluded from the ratios, then they should be excluded from the legs on a well basis rather than a lease basis. Staff Witness Murr excluded shut-in lease costs from the ratio but included the cost of shut-in wells on producing leases.

It was the position of UDC Witness Larson that shut-in lease costs should remain in the legs because these relative costs are used to allocate joint production costs which include shut-in leases as do the single product oil and gas leases. It was therefore his view that the relative costs of shut-in leases in the legs were representative for purposes of allocating joint production costs (48: 5966).

It was likewise the position of producer Witness Auten that shut-in costs should not be excluded (50:6594), but if shut-in lease costs were to be excluded from the legs, shut-in well costs should also be excluded (48:6175).

Most shut-in wells in the oil only category are found on producing leases, while the contrary is true of

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shut-in wells in the gas-only category. The effect of making the exclusion on a lease basis, as did Staff Witness Murr, rather than on the well basis, is to exclude the majority of the shut-in costs from the gas leg but only a small portion of such costs from the oil leg. The Initial Decisions in AR64-1 and AR64-2 held that the exclusion on a well basis provided a better measure of the relative costs of producing gas and oil. (See Init. Dec. AR64-1,[86] pp. 169-71, and Init. Dec. AR64-2 pp. 189-92.) Stable, representative relative cost ratios can be developed with all shut-in costs remaining in the legs; however, if any shut-in costs are to be excluded, they should all be excluded which requires that the exclusion be on a well basis rather than a lease basis.

e. Allocation of Return on Net Investment for the Joint Product Leases

If the relative cost method is to be used to allocate joint production costs in determining the range of reasonable flowing gas cost estimates, net investment for the single product legs should be used in allocating net investment between joint products on gas condensate leases. Witnesses Auten and Larson agree on this point (48:5970-6177).

In the Commission's use of the relative cost method in Opinion 338, net investment was used in establishing the ratios. Later, in Opinion 468, the Commission used

[86] This question was not reached in the Commission's decision in Opinion 586.

gross investment because it found that oil-only leases were generally more depleted than dry-gas leases, and that on joint product leases the depletion rate is the same for liquids as for gas (34 FPC at 300-01). This rationale stops short of considering two very important facts. The first is that, because the relative cost ratio is so significantly affected by production volumes, more joint product costs are allocated to liquids by the use of gross investment than the facts justify. In the later stages of depletion, oil leases are no longer producing at rates comparable to initial or early productive life rates. Yet the gross investment procedure would relate the initial undepreciated investment to those lower

[12,802]

production volumes on the oil side while at the same time relating the undepreciated gas investment to the newer and on the average higher producing rates on the gas side.

The second important fact is that it is quite rare on joint product leases for liquids and gas to be depleted at the same rate. On gas condensate leases the liquids are normally produced faster during the earlier life of the leases, while near the end of production gas is produced with a virtual absence of liquids. During most of the life of a gas condensate lease, the liquids will be relatively more depleted than the gas. The use of a net investment relative cost ratio more nearly reflects that fact (48:6178-79).

4. Alternative Cost Estimates for Flowing Gas Under Contracts Dated Prior To January 1, 1961

Producer Witness Auten presented two alternative methods for estimating costs of gas sold under contracts

dated prior to January 1, 1961 (48:6190-95; Ex. 67). In the first, which yielded a range of 25.30 to 28.94 cents per Mcf (at 13% rate of return), he used the costs computed for 1960 in Opinion 546 (40 FPC at 603) but substituted the 1969 current cost DD&A and exploration expenses presented by Dr. Sherwin in these proceedings (Ex. 63), after adjustment for pressure base and to exclude liquid credit and royalty.

The second alternative shown in Exhibit 67 is a backtrending similar to the method used by the Commission in Opinion 468 as a check on its historical costing results (34 FPC at 219). Witness Auten backtrended the current cost estimates presented by Dr. Sherwin. The result was a range from 21.83 to 28.92 cents per Mcf.

As older fields are depleted and the mix of gas currently delivered from a particular vintage begins to be more heavily weighted by newer fields, there is a tendency to offset the declining rate base. This tendency is augmented by new investment required to replace worn-out equipment, rework older wells, and provide compression facilities. The effects of inflation and increasing costs also play a part. Any realistic view of older vintage flowing gas should give

[14,053]

UNITED STATES OF AMERICA
FEDERAL POWER COMMISSION

Supplement No. 47 to Amoco Production Co.
Gas Rate Schedule No. 173

AMOCO PRODUCTION COMPANY

APPLICATION OF AMOCO PRODUCTION COMPANY FOR REHEARING

Amoco Production Company, Amoco, pursuant to Section 19(a) of the Natural Gas Act, 15 U.S.C. § 717r(a) and Section 1.34 of the Commission Rules, 18 C.F.R. § 1.34, applies for rehearing with respect to Letter Order dated December 17, 1971, and mailed to Amoco January 7, 1972, insofar as in accepting Supplement No. 47 to Amoco Rate Schedule No. 173 such Letter Order postpones the effective date of the change in rate to a date more than 30 days from the date the required notice was filed.

Pursuant to Section 4(d) of the Natural Gas Act, 15 U.S.C. § 717c(d) and Section 154.94 of Commission Regulations thereunder, 18 C.F.R. § 154.94, Amoco duly gave 30 days' notice to the Commission and to the public of the effectiveness of a change in rate by properly filing its notice with the Commission as Supplement No. 47 to its Rate Schedule No. 173. Contrary to such notice of change in rate and Section 4(d) of the Act and in excess of Commission authority under the Act, the Commission postpored by Letter Order dated December 17, 1971, and

mailed to Amoco January 7, 1972, the effective date of such

[14,054]

change in rate to a date 65 days from the date such notices were duly filed with and received by the Commission. Other than the statement "pursuant to Section 4.3 of the UDC settlement proposal approved by the Commission in Opinion No. 598," such Letter Order did not state any reason for denial of the relief requested by Amoco or for denial of Amoco's rights under Section 4(d) of the Act.

Amoco did not join in or support the UDC Settlement Proposal or its adoption by the Commission as its Opinion No. 598 and thus did not waive its rights under Section 4(d) of the Act. Regardless of purported Commission consent, other parties or groups of other parties do not have authority either to waive or dilute Amoco's rights under Section 4(d) of the Act or to empower the Commission to take action to like effect. The fact that certain other parties in return for benefits not similarly applicable to Amoco may have agreed to waive their rights under Section 4(d) of the Act does not constitute a basis for denial of the relief requested by Amoco. As is admitted in Opinion No. 598, Amoco is "comparatively disadvantaged" under the settlement adopted as the Commission's decision,[1] and as recognized in Opinion No. 598-A were it not for certain benefits primarily attributable to others, Amoco might well have been allowed "greatly" higher rates.[2]

[1] Paragraph 38 on page 18.

[2] Page 5.

[14,055]

WHEREFORE, Amoco Production Company respectfully requests that rehearing be granted on the "Effective date" provisions of the above-referenced Letter Order as such apply to Supplement No. 47 to Amoco Rate Schedule No. 173 and that such Letter Order be amended to prescribe an effective date of such change in rate no later than 30 days from the date of filing such notice with the Commission.

Respectfully submitted,

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Attorney for
Amoco Production Company

Dated at Tulsa, Oklahoma
January 26, 1972

[14,057]

Order Denying Application for Rehearing

[14,057]

UNITED STATES OF AMERICA
FEDERAL POWER COMMISSION

Before Commissioners: John N. Nassikas, Chairman; John A. Carver, Jr., Albert B. Brooke, Pinkney Walker, and Rush Moody, Jr.

FPC Gas Rate Schedule No. 173
AMOCO PRODUCTION COMPANY

ORDER DENYING APPLICATION FOR REHEARING

(Issued February 23, 1972)

Amoco Production Company (Amoco) filed on January 28, 1972, an application for rehearing with respect to the Commission's letter order issued December 17, 1971, accepting Supplement No. 47 to Amoco's FPC Gas Rate Schedule No. 173, which relates to a rate increase filing for a jurisdictional sale of natural gas in the Southern Louisiana Area, effective as of December 22, 1971, sixty-five days after the filing was made. According to Amoco, the Commission's order was mailed to it on January 7, 1972. The effective date provided in this order is in accord with the provisions of Opinion No. 598 issued July 16, 1971, in *Area Rate Proceeding, et al.* (Southern Louisiana Area), Docket Nos. AR61-2, *et al.*, AR69-1.

In its application for rehearing Amoco contends that this Commission has no power to defer the effective date of an acceptable increase beyond the 30 day notice period provided in Section 4(d) of the Act.

Order Denying Application for Rehearing

The Commission in Opinion No. 598-A issued September 9, 1971, denied, *inter alia*, Amoco's application for rehearing of Opinion No. 598 with respect to the same issue it seeks to raise here regarding the proper effective date for an acceptable increase. A number of petitions for judicial review of that case have been filed. The first petition was

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filed in the United States Court of Appeals for the Fifth Circuit in *Placid Oil Company, et al.* v. *F.P.C.*, CA5, No. 71-2761. Any question as to the validity of the Commission's action will be decided upon judicial review of that case.

Amoco's application for rehearing presents no new facts or principles of law which were not fully considered by the Commission in its December 17 order, or which having now been considered, warrant any modification of that order.

The Commission orders:

The application for rehearing filed by Amoco on January 28, 1972, is denied.

By the Commission.

KENNETH F. PLUMB
Secretary

[SEAL]